NEW SOUTH WALES TRANSMISSION ANNUAL PLANNING REPORT

2021

People. Power. Possibilities.

Transgrid

Purpose of the Transmission Annual Planning Report

The National Electricity Rules (NER) require TransGrid to conduct an annual planning review and publish the results by 31 October each year. The purpose of the review is to identify an optimum level of transmission investment which will enable TransGrid to deliver value for customers at an efficient cost.

The Transmission Annual Planning Report (TAPR) involves joint planning with each of the distribution network service providers in New South Wales (NSW) (Ausgrid, Endeavour Energy, and Essential Energy) and the Australian Capital Territory (ACT) (Evoenergy) as well as with Powerlink in Queensland, AusNet Services in Victoria, ElectraNet in South Australia and the Australian Energy Market Operator (AEMO). The objective of joint planning is to work together to develop the power system in the most efficient way for the benefit of customers.

The annual planning review takes into account the most recent forecasts of generation planting and retirement, state and local demand and condition and ratings of existing network assets. These inputs are used to identify and analyse present and emerging network constraints and asset renewal requirements.

In particular, our review:

- Identifies emerging constraints within the network and possible options to alleviate them;
- Assesses assets identified as reaching the end of their serviceable lives, confirms the ongoing requirements for the asset and considers options to address this; and
- Provides information to interested parties so that they may propose options to meet those needs, including non-network services.

Identified needs and opportunities, irrespective of the trigger for the need, are optimised within our network investment process. This is designed to respond to the changing needs of stakeholders and ensure the efficient delivery of our capital program.

As the Jurisdictional Planning Body for NSW, we provide input to AEMO's Electricity Statement of Opportunities (ESOO) and Integrated System Plan (ISP), which incorporates the National Transmission Network Development Plan (NTNDP). Broadly, the ESOO considers the adequacy of generation while the ISP sets out a whole of system plan for the efficient development of the power system and facilitates the efficient development and connection of new generation across the National Electricity Market (NEM). These reports serve as inputs to the TAPR, and we report on relevant matters arising from these publications.

Disclaimer

Foreword

Transmission will be central to the energy transformation needed to achieve economy-wide decarbonisation.

In the coming years, the patterns of electricity supply and demand will change dramatically as Australia transitions from a fossil fuel to a renewable energy based power system, leading to new constraints and challenges for the transmission network.

Already, renewables are transforming Australia's energy system faster than expected, creating congestion on the transmission network – a problem that will become more widespread over the next few years.

Congestion will be further exacerbated as electricity consumers increasingly become producers, and networks of homes combine to form virtual power plants.

Equally, as consumers begin to trade their own energy, other new business models and types of market participant are expected to emerge, requiring an agile, flexible transmission system to accommodate them.

In terms of demand in the near term, post-COVID economic recovery and new loads from mining in regional NSW, urban development, industrial precincts and data centres will grow grid-supplied demand – even with the ongoing shift to distributed energy systems.

Looking ahead, the rise of transport electrification and green manufacturing will further increase demand for renewable energy.

To support these changes, the transmission network must be:

- Strengthened to accommodate increased generation
- Expanded with renewable energy zones to facilitate the connection of new generation
- Enhanced with interconnections that allow energy to be shared between regions, supporting reliability.

Even in scenarios with very high uptake of demand-side technologies, the development of renewable energy zones and major transmission projects will still be required for energy generation, reliability and security.

Power system conditions are becoming increasingly challenging.

Transmission is also essential to maintain stability of the power system. The National Electricity Rules (NER) obligate TransGrid, as a Transmission Network Service Provider, to procure minimum required levels of inertia to keep the energy system stable.

To date, the coal fleet has been the steady hand that has allowed the system to counter rapid changes in frequency. Now, as coal-fired generation retires and is replaced with intermittent renewables, minimum load will reduce and continue to decrease, creating increasing instability.

To comply with the NER and maintain the stability of the power system, we need to invest in grid-scale battery technology with fast-frequency response and synthetic inertia.

Optimising the use of batteries in this way – by finding lowest-cost ways to fix the problem of falling inertia while also providing more dispatchable power to the energy market – will ultimately benefit consumers by putting downward pressure on energy bills.

The value of transmission to consumers is greater than its costs.

As the penetration of low-cost renewable energy increases, wholesale electricity prices will fall, providing additional benefits to consumers. In this regard, transmission will also provide a vital platform for wholesale market competition to minimise energy costs for consumers.

Beyond helping to lower prices, the projects proposed in this Transmission Annual Planning Report will also return total economic benefits of more than double their capital investment, including the creation of thousands of direct and indirect jobs.

As this Report describes, TransGrid's transmission plan will support energy transformation in NSW by strengthening, expanding and enhancing the network, increasing system stability and underpinning competition within the wholesale electricity market to drive down prices for consumers.

The result will be an affordable, secure and low-emissions energy system that returns a high economic dividend to NSW.

Brian Salter
Acting Chief Executive Officer
July 2021

About TransGrid

TransGrid operates and manages the high voltage electricity transmission network in NSW and the ACT. The network connects more than three million homes, businesses and communities to a safe, reliable and affordable electricity supply.

The transmission network transports electricity from generation sources such as wind, solar, hydro, gas and coal power plants to large directly connected industrial customers and the distribution networks that deliver it to homes and businesses. Comprising 119 substations, over 13,204 kilometres of high voltage transmission lines, underground cables and five interconnections to QLD and VIC, the network is instrumental to the electricity system and economy and facilitates energy trading between Australia's largest states.

Figure 1 sets out TransGrid's role in the electricity supply chain. **Figure 2** and **Figure 3** show TransGrid's network.

Figure 1 – TransGrid within the electricity supply chain

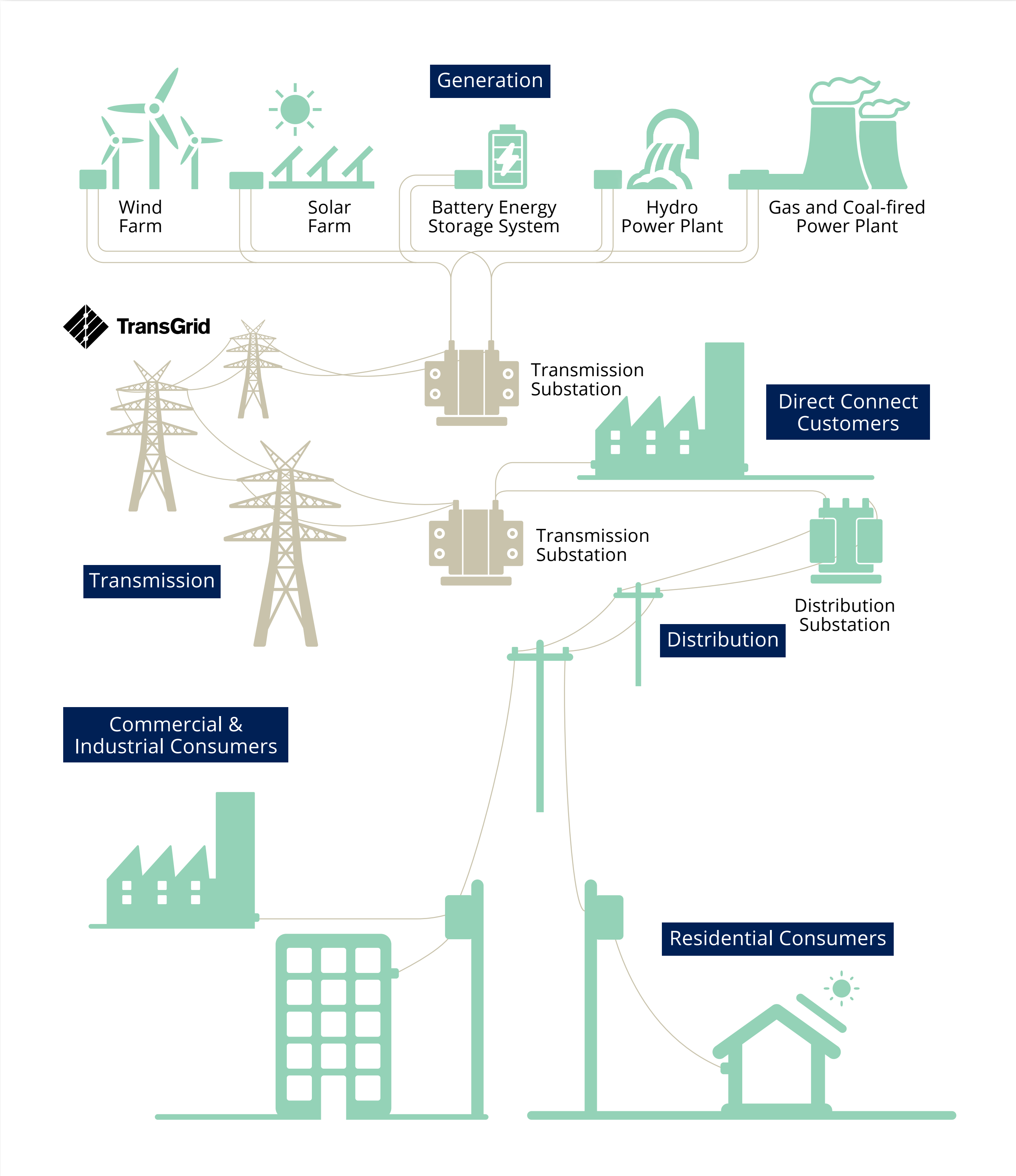


Figure 2 – TransGrid's electricity network map

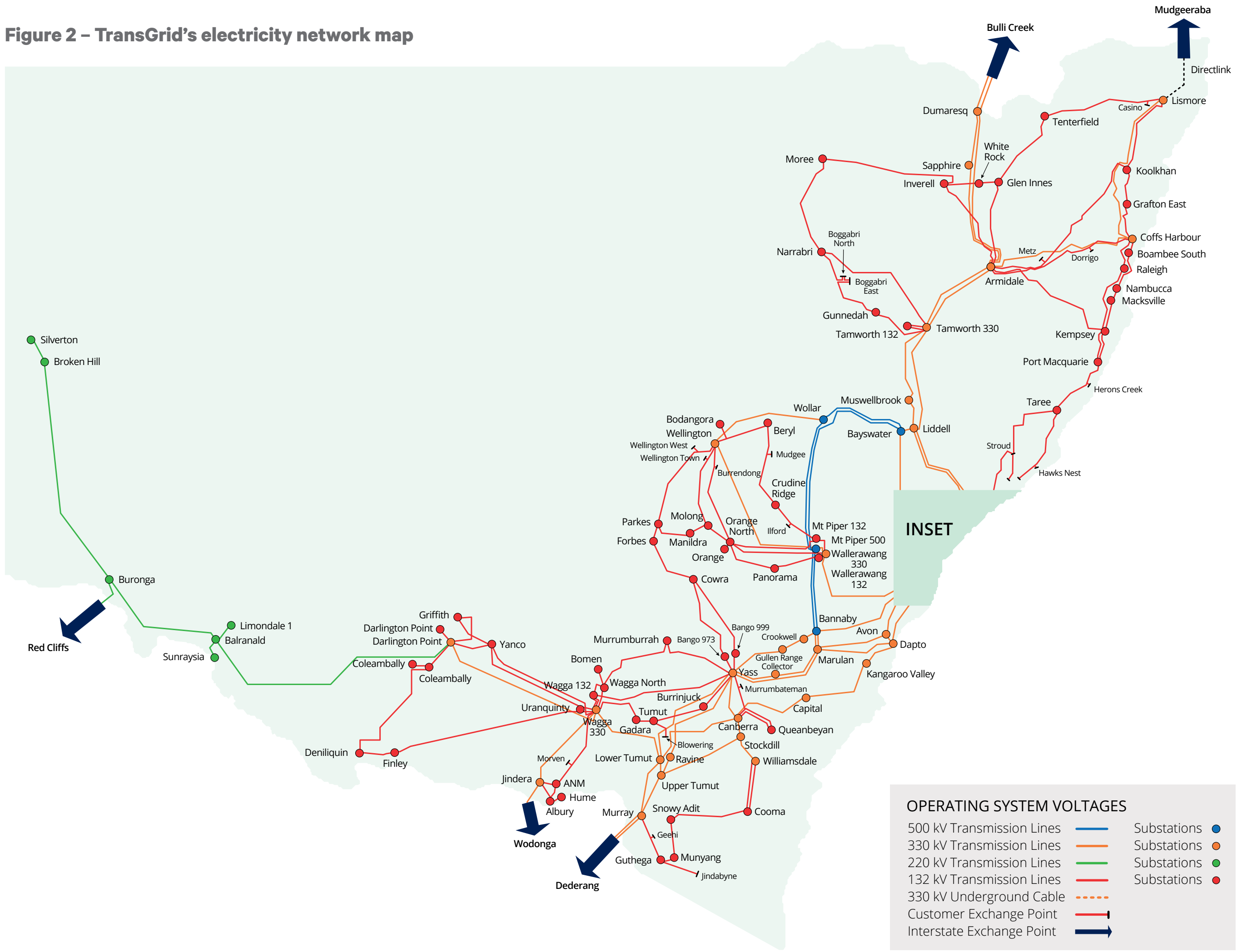
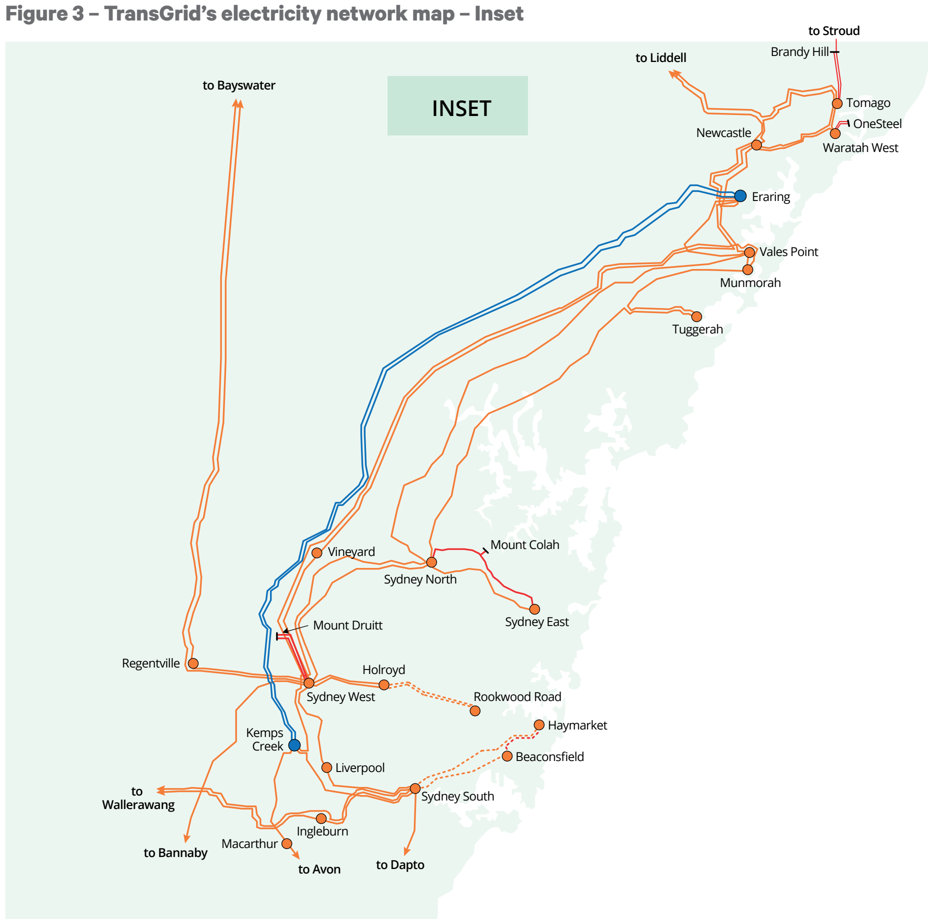


Figure 3 – TransGrid's electricity network map – Inset



Executive Summary

TransGrid is leading the transition to a clean energy future by supporting and ensuring a smooth transition to renewables. Timely investment in new infrastructure is essential for the power system's successful transformation to the energy system of the future.

Transmission will be central to the energy transformation:

Chapter 1

Australia's energy system is transitioning to a renewables based power system faster than previously envisaged, leading to increased congestion on the transmission system.

In the medium to long term, technology shifts in transport and green manufacturing will significantly change the patterns of electricity usage in Australia and NSW. As more people buy electric vehicles, load growth will increase dramatically, requiring the augmentation of transmission infrastructure throughout the network.

Collectively, all of these factors mean power system conditions will become increasingly challenging, creating a growing need for ancillary services to improve stability. Regulatory reforms will oblige TransGrid to provide inertia network services.

Transmission is key to providing resilience in the power system, particularly in a changing climate when increasing severity and frequency of extreme weather events creates challenges to managing a reliable system.

Transmission network developments:

Chapter 2

In response to the above challenges, we have identified major projects to:

- Meet the 2020 ISP major projects including EnergyConnect, HumeLink, QNI upgrade and VNI upgrade as well as proposed Renewable Energy Zones including Central-West Orana and New England.
- Address emerging constraints and support the connection of new, low-cost renewable generation, especially in remote locations where the existing network capacity is limited
- Supply growth areas in north-western and south-western Sydney, including co-locating a grid-scale battery with a transmission substation and conducting a fast frequency response pilot
- Supply areas with growing industrial load in regional NSW, including maintaining reliable supply to Bathurst, Orange and Parkes areas where network constraints will be unable to accommodate predicted long-term demand.

We will also continue to replace or refurbish transmission lines, substation assets and secondary systems to ensure network reliability.

Network support opportunities:

Chapter 3

The NSW transmission network is becoming more congested in weak areas as more spot loads and variable renewables connect. Network support may be able to assist with maintaining voltage stability and ensuring power flows on transmission lines and equipment stay within their ratings. We have identified 12 locations where network support could assist with deferring constraints over the next 10 years.

A Request for Proposals has been issued for non-network solutions for maintaining reliable supply in: Bathurst, Orange and Parkes areas; and the North West Slopes area. A Request for Tender has also been issues for non-network solutions in Inner Sydney. Three further locations have been identified where there may be potential to issue Requests for Proposals for non-network solutions in the next 10 years.

Forecasts and planning assumptions:

Chapter 4

Demand growth has been flat or falling in recent years and growth will most likely remain weak over a 10-year forecast horizon. Over the next decade, the annual NSW & ACT energy consumption is forecast to grow at an average rate of 0.5 per cent per annum, after an initial decline due to the effects of COVID-19. Summer maximum demand is expected to grow by around 1.1 per cent per annum and the winter maximum demand by around 0.4 per cent per annum on average.

In terms of supply, this planning review incorporates an additional 1,477 MW of new renewable generation, which has committed to connect at various locations in NSW since June 2020. We continue to receive connection enquiries for projects at various stages of development across NSW. Only a fraction of this proposed generation can be accommodated in TransGrid's current network due to declining spare capacity.

Assessment of power system security:

Chapter 5

While most parts of the NSW transmission network currently have sufficient system strength, we project a shortfall in generation to meet peak demand as coal-fired generation retires. Specifically, we expect shortfalls in system strength and system inertia following the retirements of Liddell, Vales Point and Eraring Power Stations or if coal-fired power stations move to flexible operation.

TransGrid is working to develop least-cost solutions to these shortfalls as new generation connects and large-scale energy zones are established.

Shortfalls in system strength can be met by additional new generation, greater interconnection, storage and demand management. This is being managed by the connection of new generation to the network and projects to increase network capacity.

A secure level of inertia may be achieved using emerging fast frequency response devices, such as the grid-scale batteries currently being piloted.

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Transmission will be central to the energy transformation

- Energy market conditions are driving faster-than-expected changes in the energy system
- Technology shifts are forecast to drive changes in patterns of electricity usage
- Economic conditions are forecast to drive growth in electricity demand
- Power system conditions are becoming increasingly challenging

1.1 Changing energy market conditions

1.1.1 The energy transition is happening faster than anticipated

Australia's energy system is transitioning to a renewables based power system – faster than previously envisaged. Almost 2 GW of large scale solar and wind capacity was added to the National Electricity Market (NEM) in 2020, and a further 8 GW of large scale solar and wind generation is currently under construction[1]. The pipeline is even larger – 300 generation and storage projects, totalling 55,000 MW, are currently proposed across the NEM.[2]

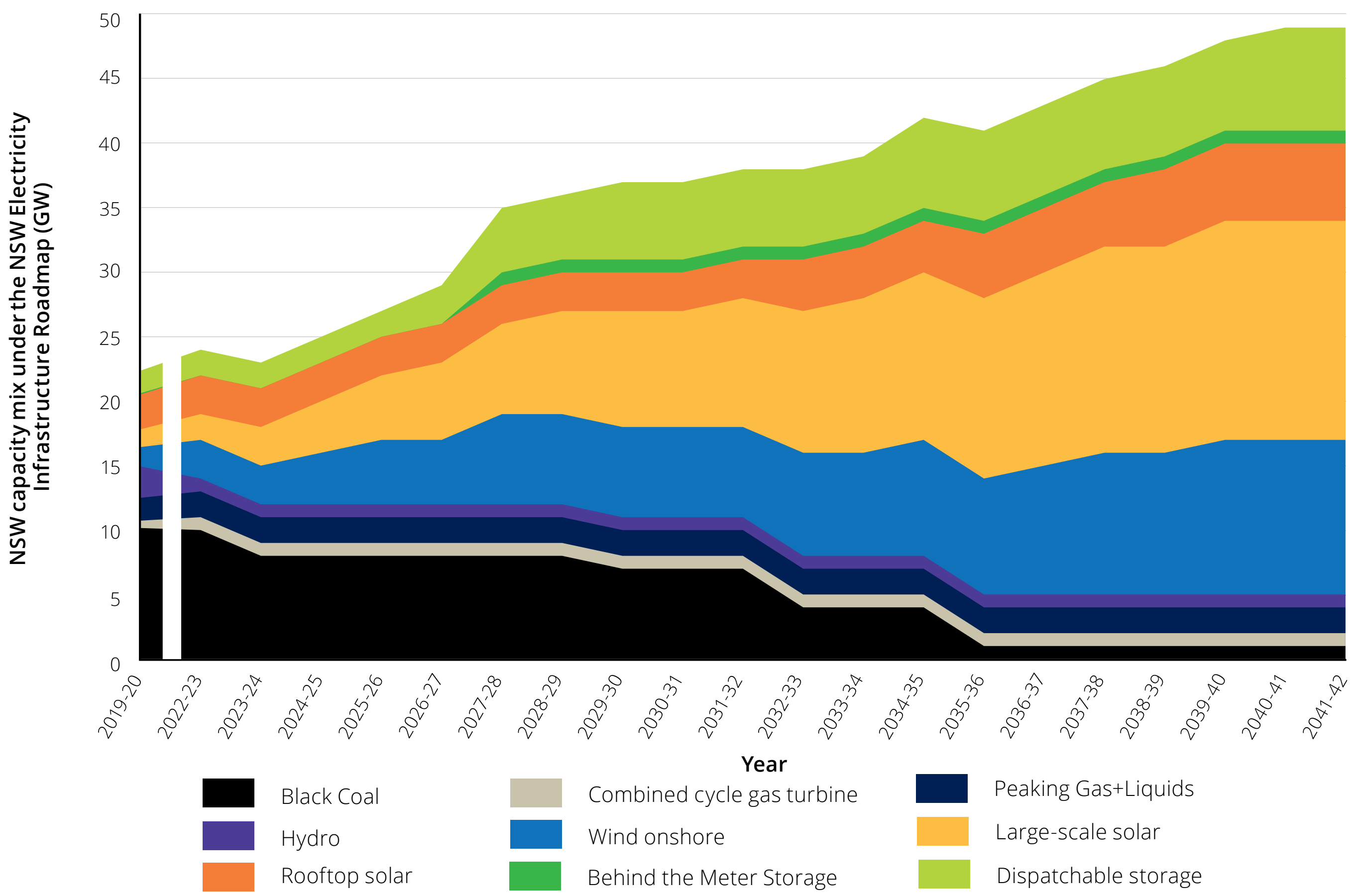
Australia is also leading the world in the growth of rooftop solar, with over 3 GW of rooftop solar was installed in 2020 and one in four households now have rooftop solar[3].

In NSW alone, 6,892 MW of solar and wind capacity is at various stages of the connection process. The NSW Government's Electricity Infrastructure Roadmap legislation will ensure an additional 12GW of large scale solar and wind capacity installed in NSW by 2030. **Figure 1.1** projects the NSW electricity generation capacity mix to 2042, under the Electricity Infrastructure Roadmap.

"Based on the pipeline of registered and commissioned renewable projects, we're well ahead of the 2020 Integrated System Plan's 'step change' scenario which would see more than 90 per renewable penetration, including rooftop solar PV, by 2040." AEMO[4]

NSW projected generation mix

Figure 1.1: Actual and projected generation capacity in NSW



Source: TransGrid and the NSW Government

1 https://assets.cleanenergycouncil.org.au/documents/resources/reports/clean-energy-australia/clean-energy-australia-report-2021.pdf
2 https://aemo.com.au/newsroom/media-release/aemo-updates-2020-esoo
3 https://assets.cleanenergycouncil.org.au/documents/resources/reports/clean-energy-australia/clean-energy-australia-report-2021.pdf
4 https://aemo.com.au/newsroom/news-updates/new-wind-and-solar-registrations-double-in-victoria .

1.1.2 Congestion on the transmission network will become more widespread

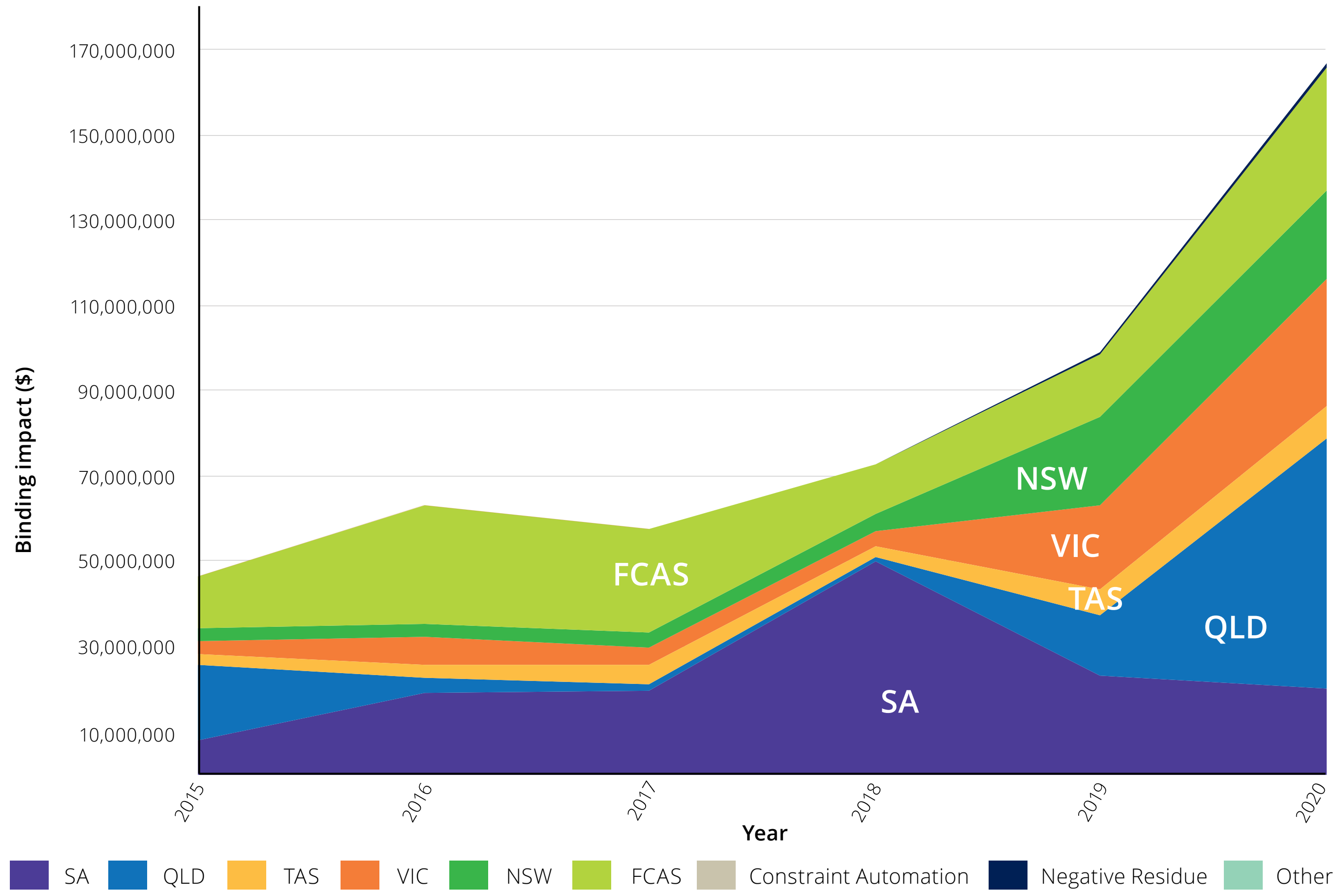
Our electricity transmission network was designed to supply electricity from large coal generators to load centres and to connect to Queensland and Victoria. The growth in renewable energy has meant that new renewable generators are connecting to weaker parts of the transmission network.

The growth in renewables is leading to increased congestion on the transmission system. 5,665 MW of renewable energy generation has enquired to connect into TransGrid's network in the last year, yet there's only hundreds of MW of spare capacity available.

Growing congestion isn't limited to NSW, and the trend in **Figure 1. 2** is clear – congestion, and the lost value from it has been increasing, and will keep increasing over time without further augmentation of the network. New transmission is essential to unlock these constraints and enable our energy transformation.

Lost value due to constraints in the NEM

Figure 1.2: Lost value due to constraints in the NEM. Source, AEMO, 2021



Source: AEMO, 2021

1.1.3 Difficult conditions for coal generators

Over the coming years, the continued growth in renewable energy installations, low wholesale electricity prices and a possible strengthening of Australia's emissions reduction targets could contribute to the earlier than anticipated withdrawal of coal-fired generation.

Wholesale electricity prices are likely to remain lower in the coming years than have been seen in the previous four years, due to the continued influx of low cost renewable energy into the system. Electricity price projections from Reputex[5] suggest that under AEMO's 2020 Integrated System Plan central case *"Wholesale prices (average all regions) are forecast to remain between $50 and $70/ MWh over the next decade."* And under a step change *'As these distributed assets accumulate, 'baseload' demand profiles are forecast to be eroded, helping to maintain average wholesale prices below $60 per MWh, and increasing the value of flexible capacity to balance the higher penetration of variable renewable energy generation."*

The International Monetary Fund has slammed "grossly insufficient" global policies to combat climate change, predicting a climate "catastrophe" where global temperatures rise 5°C unless governments impose steadily rising taxes on carbon dioxide emissions[6]. Yet global momentum to set more aggressive emissions reduction targets is increasing.

5 https://www.reputex.com/research-insights/wholesale-electricity-prices-to-2040-under-a-1-5-2c-step-change-scenario/
6 International Monetary Fund, 2020, World Economic Outlook, https://www.imf.org/en/Publications/WEO/Issues/2020/09/30/world-economic-outlook-october-2020

A comparison of Australia's 2030 target of a 26-28% reduction on 2005 levels[7] suggests we are falling behind:

- United Kingdom: 78% by 2035 on 1990 levels (legislated?)[8]
- USA: 50-52% by 2030 on 2005 levels (proposed)[9]
- Europe: 55% by 2030 on 1990 levels (proposed)[10]
- Canada: 40-45% by 2030 on 2005 levels
- Japan: 46% by 2030 on 2013 levels
- Australia: 26-28% by 2030 on 2005 levels[11]

To facilitate the decarbonisation of our economy, to reduce congestion in system and to secure low cost energy, new transmission links are essential.

1.2 Changes in patterns of electricity usage

1.2.1 Technology shifts in transport and manufacturing will significantly change the patterns of electricity usage in Australia and NSW Region.

Electric Vehicles

Alongside the transition to renewable energy from traditional fossil fuel sources in power generation, a huge change is underway in the transportation sector with the advent of vehicles which are now powered by electricity.

A number of countries and regions in the world have put forward targets as to when traditional petrol and diesel powered cars sales will be stopped completely or reduced as shown in **Figure 1.3**.

Figure 1.3: Passenger vehicle electrification goals in major countries[12]

	2025	2030	2035	2040	2045	2050
100% electric	Norway	Netherlands		Canada Sri Lanka Spain		Costa Rica Germany
25-50% electric	China	India Japan South Korea				
No petrol or diesel		Denmark Iceland Ireland Sweden Scotland	UK	France Portugal Singapore		

7 https://www.industry.gov.au/policies-and-initiatives/australias-climate-change-strategies/international-climate-change-commitments#:~:text=Australia%20first%20communicated%20its%20NDC,below%202005%20levels%20by%202030.&text=Australia%20will%20submit%20its%20next,to%20the%20UNFCCC%20in%202025.
8 https://www.gov.uk/government/news/uk-enshrines-new-target-in-law-to-slash-emissions-by-78-by-2035#:~:text=The%20UK%20government%20will%20set,today%20(Tuesday%2020%20April).
9 https://www.whitehouse.gov/briefing-room/statements-releases/2021/04/22/fact-sheet-president-biden-sets-2030-greenhouse-gas-pollution-reduction-target-aimed-at-creating-good-paying-union-jobs-and-securing-u-s-leadership-on-clean-energy-technologies/
10 https://ec.europa.eu/clima/policies/strategies/2030_en
11 https://www.industry.gov.au/policies-and-initiatives/australias-climate-change-strategies/international-climate-change-commitments#:~:text=Australia%20first%20communicated%20its%20NDC,below%202005%20levels%20by%202030.&text=Australia%20will%20submit%20its%20next,to%20the%20UNFCCC%20in%202025.
12 https://theicct.org/sites/default/files/publications/update-global-EV-stats-sept2020-EN.pdf

Along with the targets from various countries, carmakers including Volvo, Ford Europe and GM have already announced commitments to phase-out combustion engines, with four commitments coming out in early 2021 alone. Others such as Volkswagen and Peugeot are ending investments in and development of new combustion engines. From the technology point of view, electrification of road vehicles is now inevitable and is the optimal and most cost-effective decarbonisation path for the automotive industry.

Figure 1.4: ICE phase out plan for major car manufacturers

	2020	2025	2030	2035	2040	2045	2050
Net-zero targets			Rolls Royce		General Motors Daimler Jaguar Volvo		Ford PSA Group Renault Volkswagen Nissan Toyota Honda
ICE phase out		Jaguar	Ford Volvo	General Motors	Honda		
End ICE investment	PSA Group	Volkswagen					

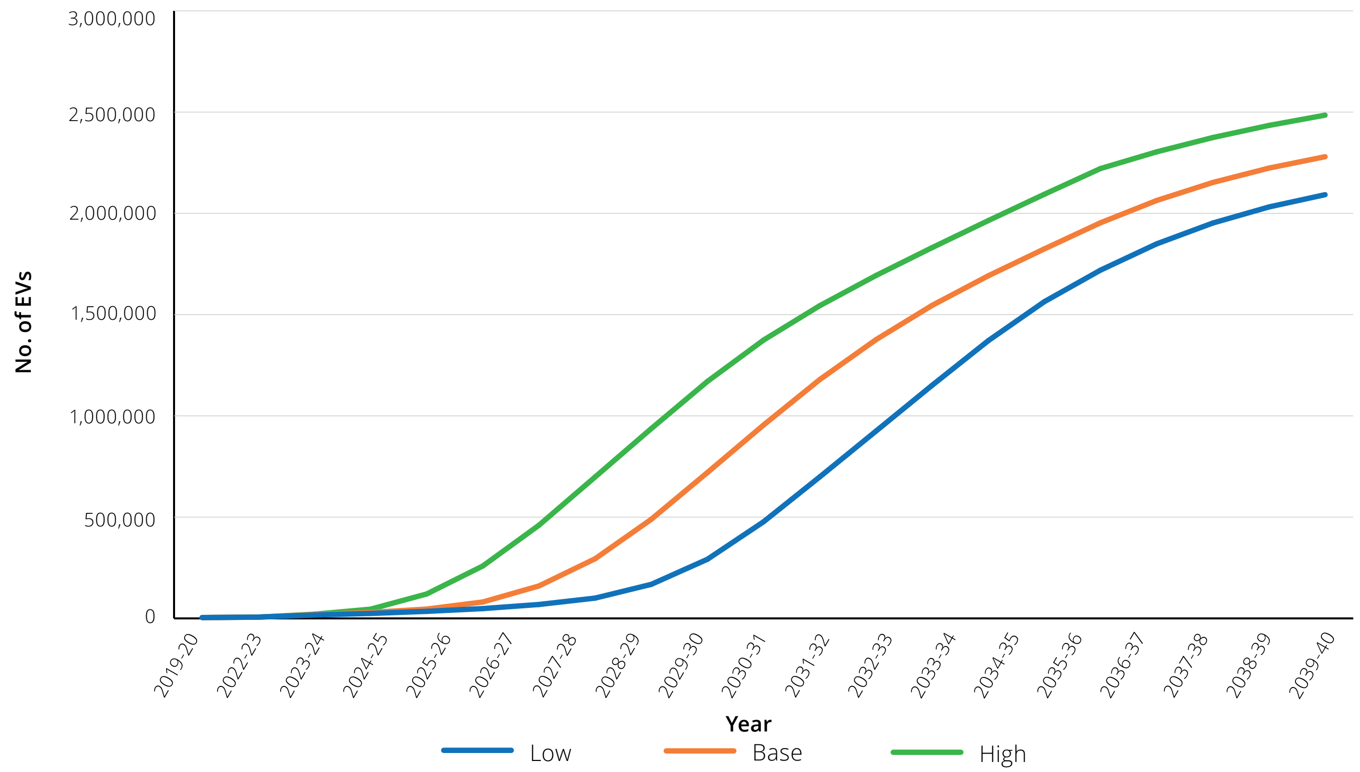
Source: BloombergNEF

Australia no longer has car manufacturing plants within the country, and relies on internationally produced cars. With worldwide manufacturing being restructured in the coming decades to go fully electric, the price of electric vehicles will be reduced and Australians will follow the world electric vehicle trend.

A recent study[13] by Energeia for TransGrid shows that EVs would comprise nearly 50% of all vehicles in use by 2040 in the NSW Region.

13 Electric Vehicle Uptake in NSW & ACT, Energeia – May 2021

Figure 1.5: Forecast for number of Electric Vehicles - NSW & ACT



Source: Energeia, 2021

As more people buy electric vehicles load growth in this region will increase dramatically and likely require the augmentation of transmission infrastructure throughout the Sydney network.

Alongside the growth in demand from electric vehicle load on the network, new technologies like virtual power plants[14] are emerging. This will influence transmission networks by causing changes in load and generation patterns.

Green manufacturing[15]

Australia has access to high quantities of low cost renewable energy, which can be used for hydrogen production. Apart from being used for domestic purposes, hydrogen is forecasted to be exported to other countries.

Hydrogen can be used in fuel-cell electric cars and trucks, hydrogen-powered electricity turbines, container ships powered by liquid ammonia[16] and as a substitute for natural gas.[17] Due to the projected rise in manufacturing of electric vehicles and other potential uses, demand for hydrogen which has grown more than threefold since 1975 continues to rise.[18]

Minerals[19] are essential components in many of today's rapidly growing clean energy technologies – from wind turbines and electricity networks to electric vehicles. Demand for these minerals will grow quickly as the clean energy transition gathers pace. The rise of low-carbon power generation to meet climate goals also means a tripling of mineral demand from this sector by 2040.

Australia has large reserves of minerals used in renewable technologies[20], being one of the top five countries with lithium reserves in the world.[21]

Hydrogen and mineral production technologies are high in electrical demand. New transmission is essential to unlock these new technologies.

14 Aggregates of individual household batteries interconnected via communication signals
15 Green manufacturing refers to production processes which are low in pollution and overall waste production. Green manufacturing includes green steel refineries and green mining. Green steel refineries use hydrogen and green mining minerals .
16 Ammonia is made from hydrogen
17 Hydrogen can potentially be used instead of natural gas (in gas pipelines), to fuel furnaces, boilers, stoves and other building applications.
18 https://www.iea.org/reports/the-future-of-hydrogen
19 https://www.iea.org/reports/the-role-of-critical-minerals-in-clean-energy-transitions/executive-summary
20 Minerals used in renewable technologies are lithium, cobalt etc.
21 https://www.ga.gov.au/scientific-topics/minerals/mineral-resources-and-advice/australian-resource-reviews/lithium

1.3 Economic conditions to drive growth in demand

1.3.1 Return to economic growth after COVID-19

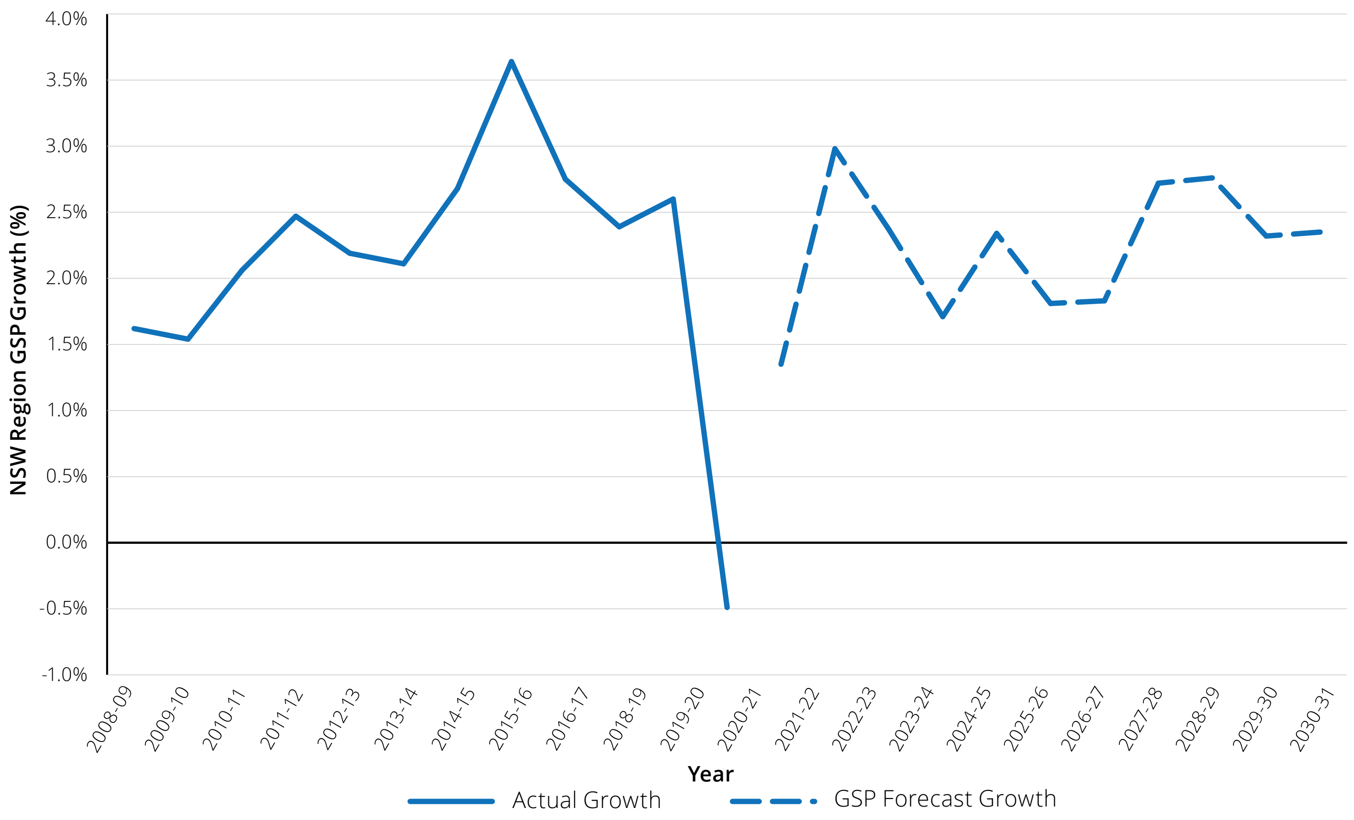
While technological change will transform the patterns of electricity consumption in the coming decades, a return to a healthier economic and population growth post COVID-19 is expected to have a positive impact on energy growth in the short term.

COVID-19 related lockdown and restrictions on economic activity caused the NSW Region economy to contract in FY 2019-20. Last year reputed economic consultants like BIS Oxford Economics and Deloitte Access Economics had forecast negative growth continuing well into FY 2021-22.

However, actual Gross State Product (GSP) data for 2019-20 revealed that the contraction was much smaller than originally anticipated. Updated forecasts from BIS Oxford Economics show that the NSW Region economy is expected to grow by 1.3% in 2020-21 and 3% in 2021-22 and return to the trend rate of growth later in this decade. This augurs well for driving future energy growth in the NSW Region.

The economic modelling in this report does not take into consideration the impact of the July 2021 lockdown in NSW due to the ongoing COVID-19 outbreak. A preliminary look at the July 2021 consumption data did not reveal any major downturn.

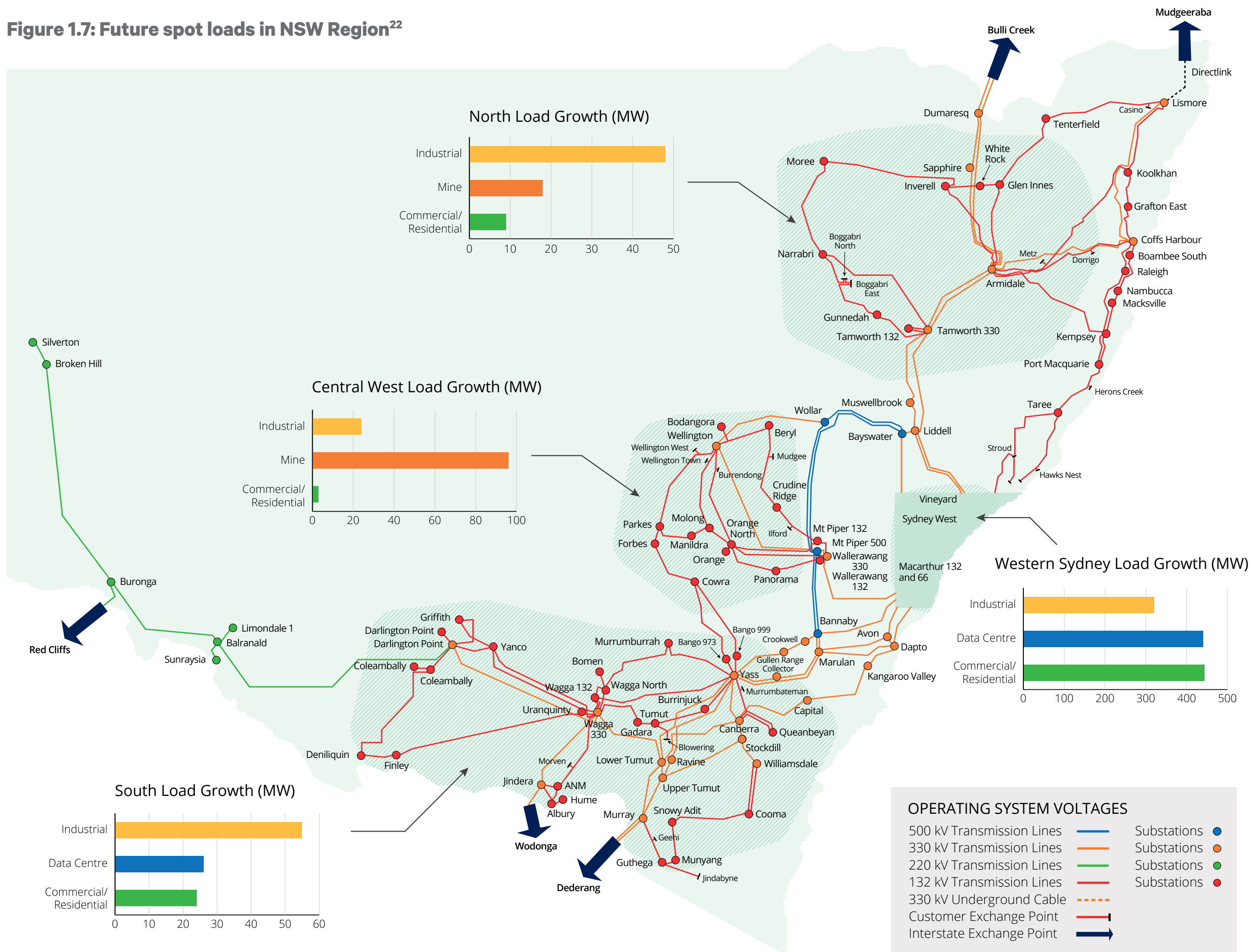
Figure 1.6: NSW economic growth



Source: BIS Oxford Economics 2021

1.3.2 Future spot loads in NSW Region

Figure 1.7: Future spot loads in NSW Region[22]



Forecasted spot load growth in different Regions of NSW during time frame covered by this document (2021-2030), is shown in **Figure 1.7**[23] as well as which development type will dominate load growth in relevant regions:

- **Western Sydney (within Broader Western Employment Area including Aerotropolis)**
  Light commercial (warehouses) and residential developments, as well as high demand data centres, influenced by construction of the Western Sydney (Nancy-Bird Walton) Airport at Badgerys Creek and Metro Western Line.
- **Central West NSW**
  Extension of existing and development of new mines, as well as proposed development of the NSW Government supported Special Activation Precincts.[24]
- **Northern NSW**
  Enhanced industrial activity, such as proposed major gas project, and mining.
- **Southern NSW**
  New mining/industrial developments such as quarries and manufacturing, and proposed data centres in ACT.

New transmission is essential to meet the growing demand for electricity in areas of the transmission network.

22 Spot Load Growth in South Region is inclusive of Summer and Winter loads
23 Spot loads from the above graph include spot loads connected to network owned by distributors and spot loads connected directly to TransGrid transmission network.
24 Special Activation Precincts are designed as hubs with main activities being freight and logistics, recourse recovery and intense agriculture.

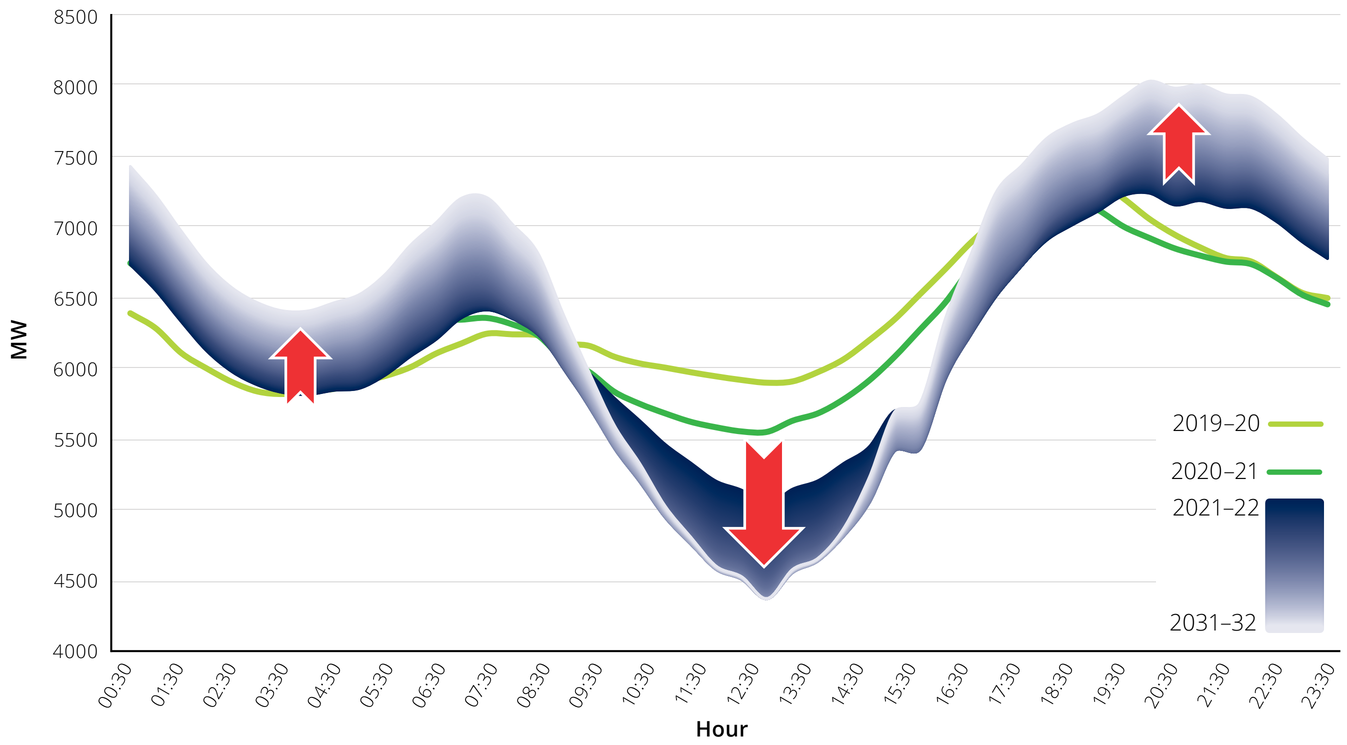
1.4 Power system conditions are becoming increasingly challenging

1.4.1 Minimum load is decreasing

Historically, the daily load profile as delivered by the TransGrid transmission network has seen daily minimum demands occurring during the night time (typically around 4am) when industries and commercial premises are mostly closed and households are sleeping. However, the installation of small scale rooftop PV systems and distribution connected solar farms is progressively changing the characteristics of daily demand required to be supplied. The cumulative effect of the power produced by the small scale renewable energy has the effect of hollowing the daily demand profile as shown in **Figure 1.8**.

Timing of minimum operation demand in NSW is bi-modal and currently experiences daily minimum demand in the early morning or around noon. Over the forecast horizon, distributed PV is expected to have an increasing impact on daily minimum demand levels. The so called 'duck curve' can be seen to emerge creating a new annual minimum demand in the middle of the day from 2021/22. Further, it is anticipated that the night time demand on a minimum demand day is increasing over the next 10-20 years due to the underlying demand growth which is not offset by PV systems.

Figure 1.8: Minimum demand (Actual and forecast) daily load curve for NSW



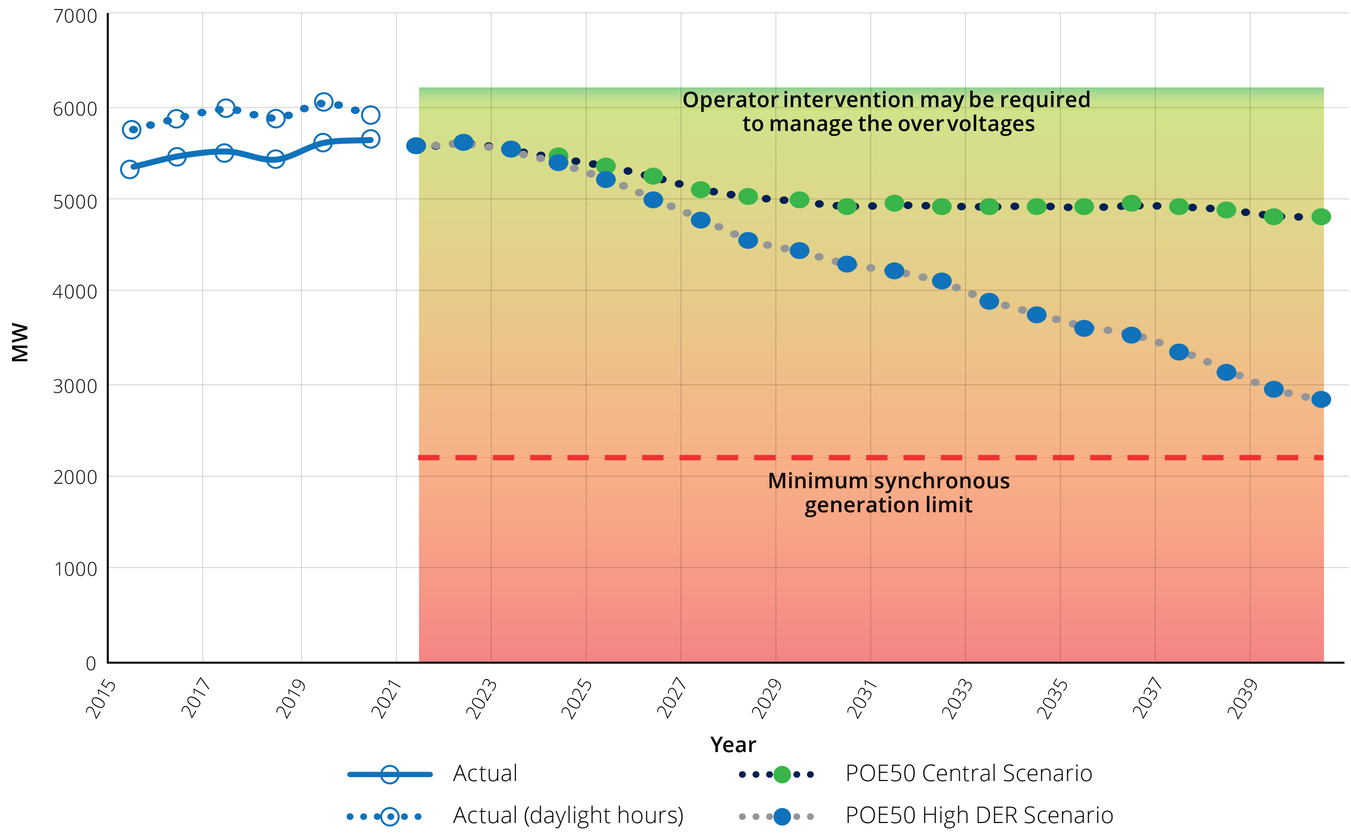
Source: TransGrid 2021 Minimum demand forecasts

The minimum demand projection for NSW for the next 20 years is illustrated in **Figure 1.9** illustrating the declining trend in minimum demand due to uptake in distributed PV systems.

AEMO intervention such as line switching may be required to manage transmission voltages when minimum demand falls below approximately 6 GW, which has already occurred in NSW on both 4 April and 6 April 2020 when demand fell to approximately 5.6 GW and 5.8 GW respectively.

There is a need for sufficient demand to support the minimum loading levels for synchronous generating units in the region, required for secure provision of frequency control, inertia, and system strength services which is estimated between 1.6 – 2.2 GW for NSW. It is noted that forecast demand under high DER Scenario[25] will be approaching this minimum loadings levels for synchronous generating units towards Year 2040.

Figure 1.9: Minimum demand outlook for NSW



Source: AEMO ESOO 2020 and TransGrid forecast data

This trend is likely to present challenges to the power system. Synchronous generators will be required to ramp up and down more frequently in response to daily demand variations. However, generation capacity to meet the evening peaks may become scarce if synchronous generators are being displaced in the middle of the day due to minimum demand or do not have adequate flexibility to ramp up for the evening peak periods. This is likely to progressively increase the reliance on peaking generation over the peak demand period.

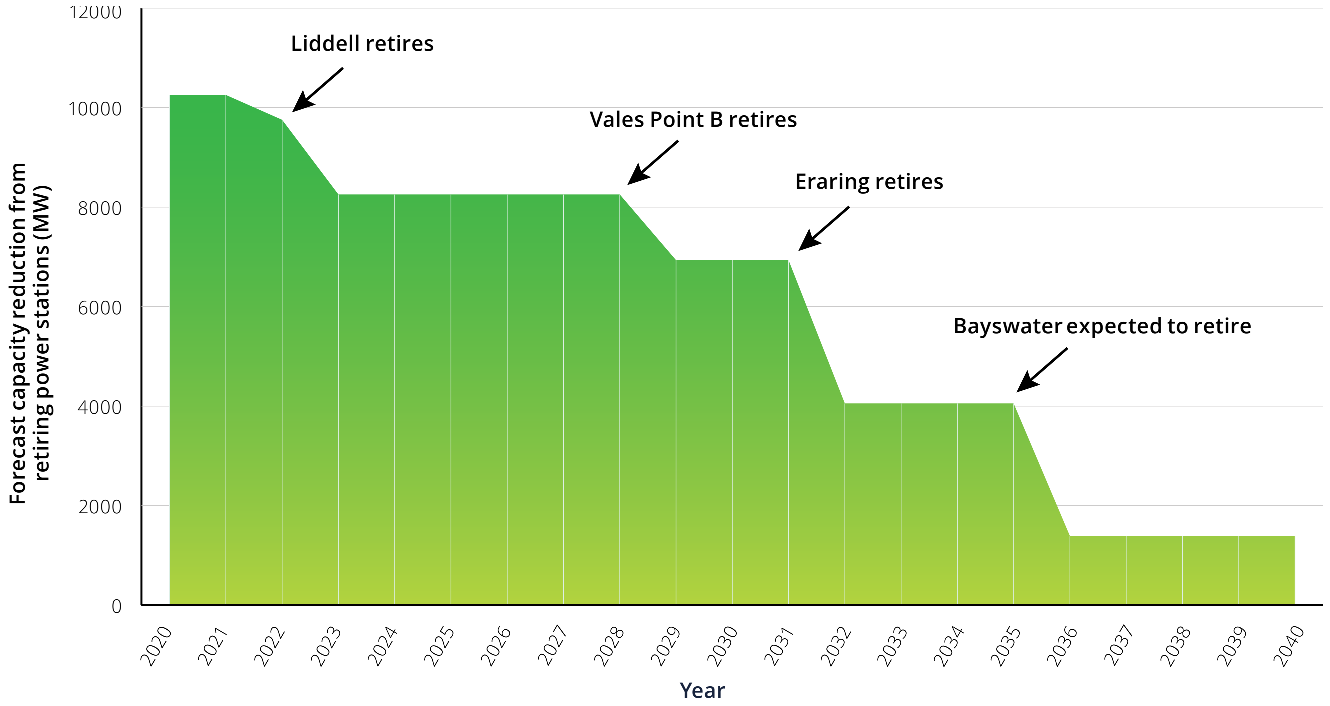
1.4.2 There is a growing need for ancillary services to provide stability

While scheduled generator retirement dates provide a useful indication for planning the Network. Generators are permitted under the National Electricity Rules (NER) to close with as little as three years' notice. Some coal fired generators are considering moving to flexible operation. These changes may come earlier due to market conditions and it is prudent to be prepared to bring forward projects to integrate new generation and improve capacity for existing generation.

As generators retire or move to flexible operation, the levels of inertia and system strength in NSW will also reduce. Based on scheduled retirement dates as shown in **Figure 1.10**, system strength remediation will be required in the late 2020s and additional inertia services in the early 2030s as depicted in **Figure 1.11**. The retirement schedule for existing generators highlights the pressing need for transformation of the power system.

25 High DER: AEMO ISP Scenario Classification Higher distribution PV uptake compared to the Central Scenario

Figure 1.10: Scheduled retirement of thermal plants in NSW

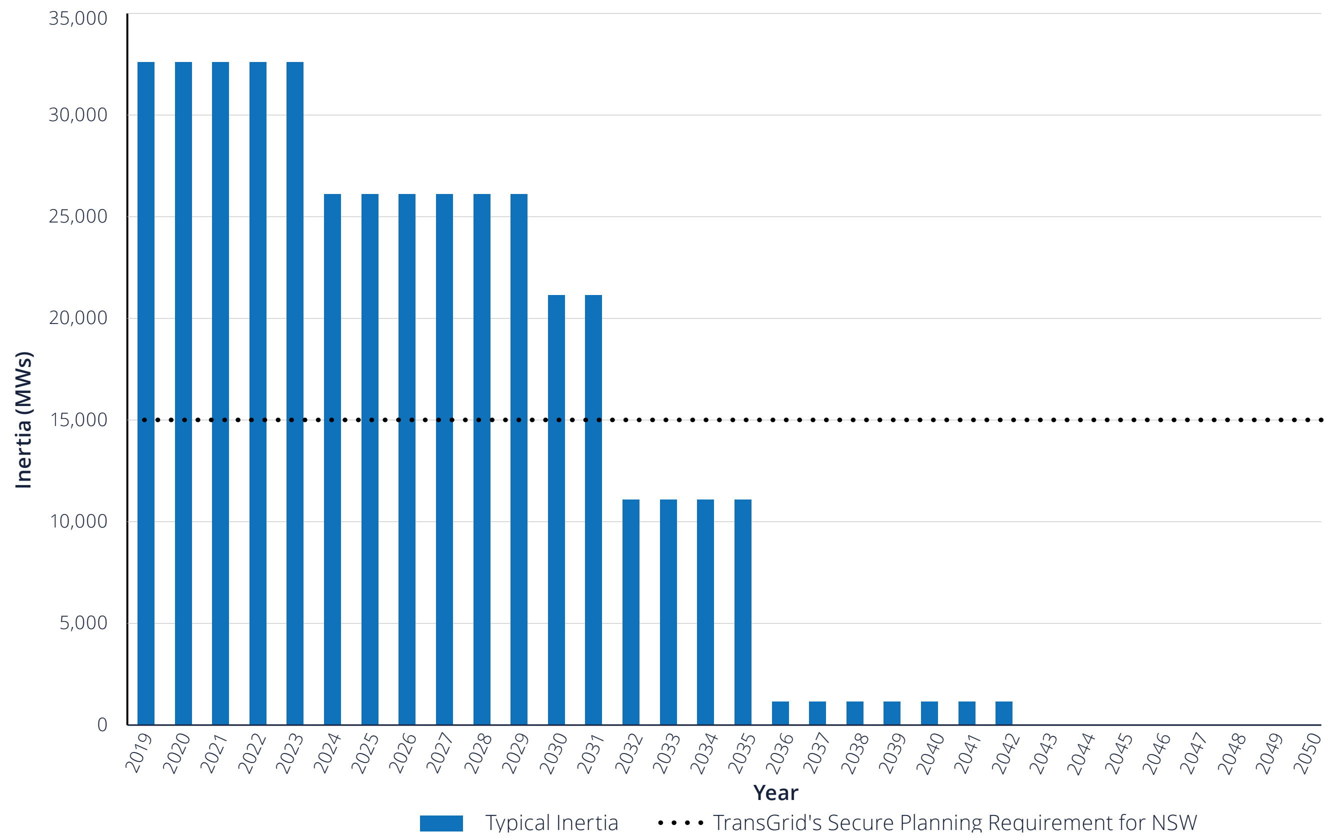


Source: The information on expected closure dates is provided to AEMO by market participants.

As more renewable generation is connected, the power system will soon reach the point where further connection of renewable generation would displace other renewable generation. Timely investment in transmission is therefore essential for the continued transformation of the power system.

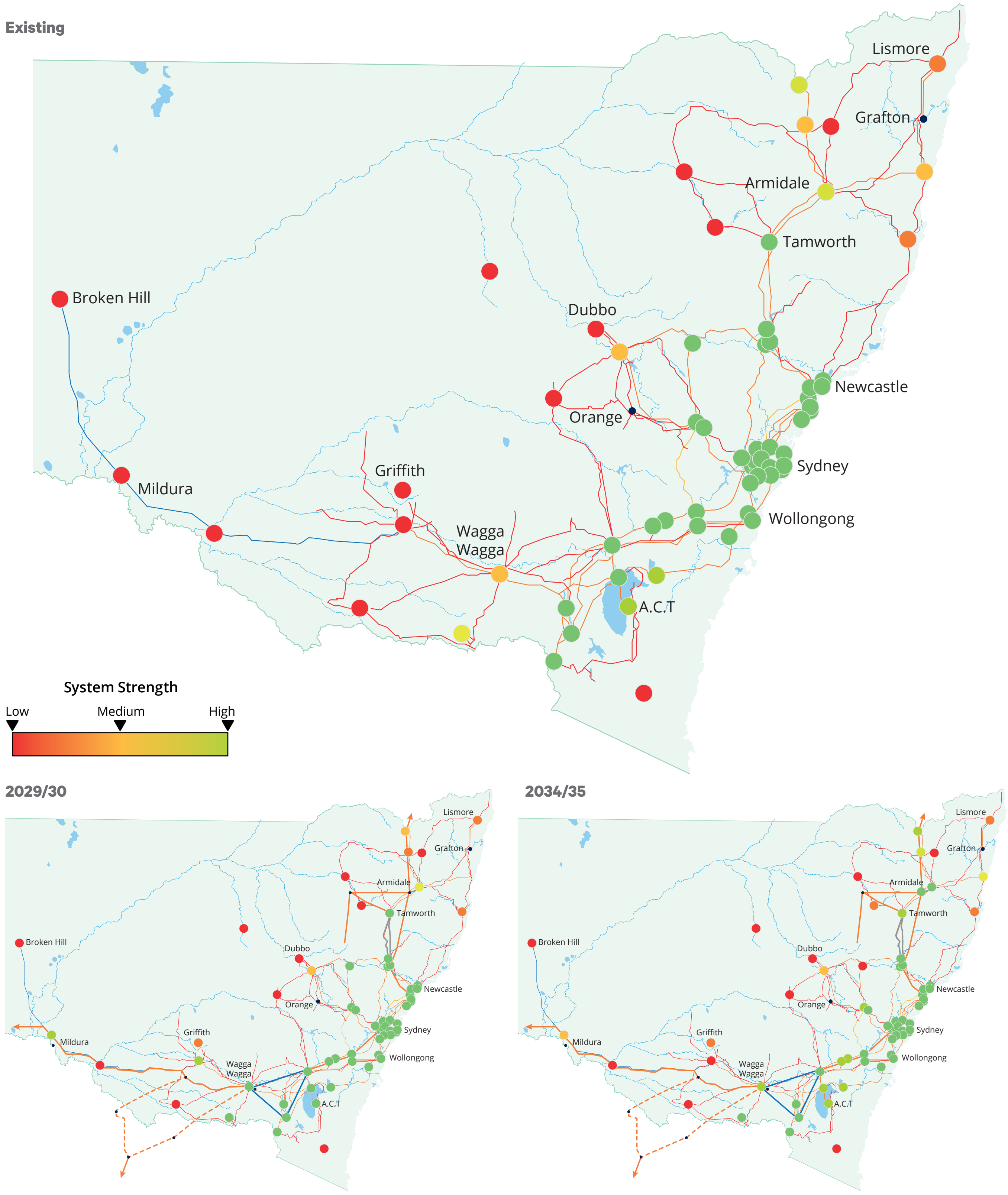
In addition, the Energy Security Board (ESB) and the Australian Energy Market Commission (AEMC) are progressing major regulatory reforms which will affect future provision of system strength and inertia – the post-2025 NEM market design project, and the consideration of seven NER change requests relating to the provision of system services. As per NER Clauses 4.3.4(j) and 5.20B.4 (a) of the NER, as the inertia service provider TransGrid is obliged to provide inertia network services if an inertia shortfall has been identified.

Figure 1.11: System inertia (typical) reduction due to synchronous generator retirement in NSW



Source: TAPR 2020

Figure 1.12: System strength outlook: Existing and future projections



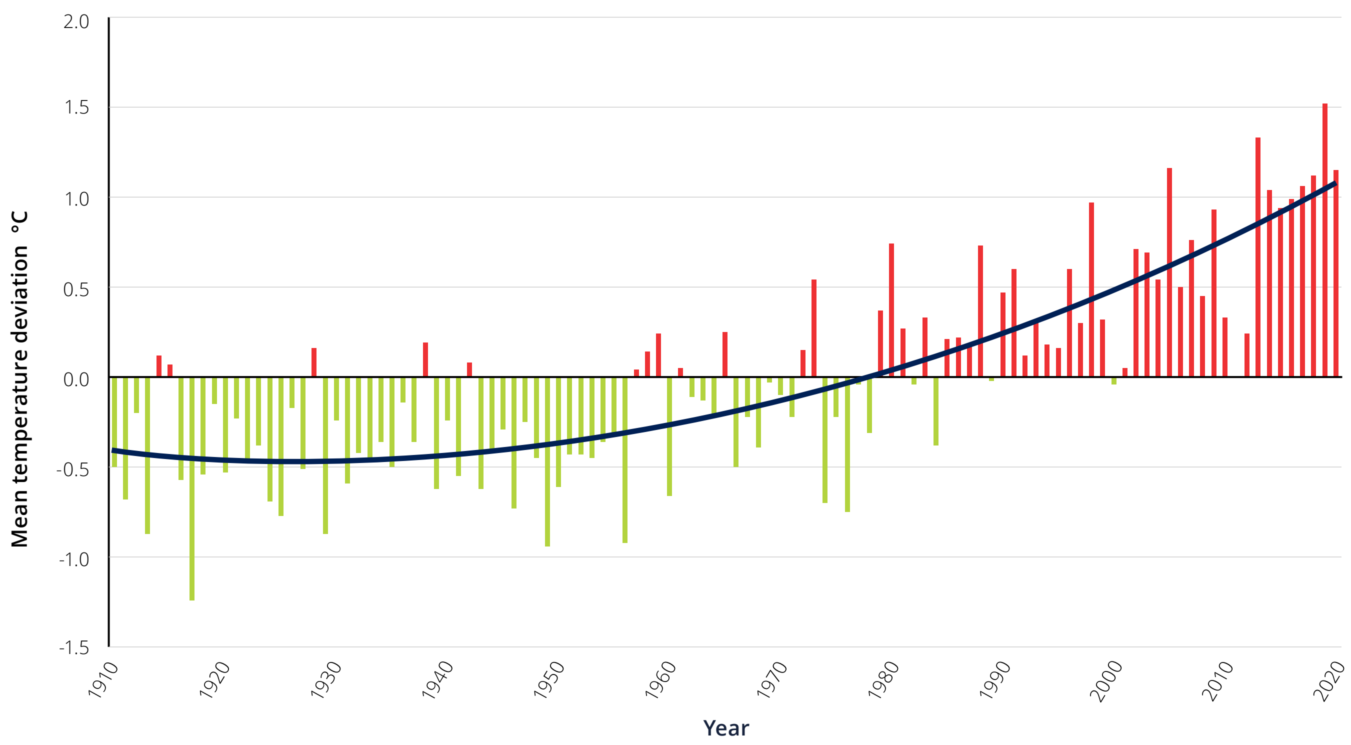
Source: AEMO interactive map for system strength https://www.aemo.com.au/aemo/apps/visualisations/map.html

Figure 1.12 illustrates the locational based system strength in the transmission network nodes as at now and over the next 15 years. The existing low system strength areas in New South Wales are noted in the far West and South West of the network. The planned network augmentations for the Energy Connect project including the 330 kV transmission lines and synchronous condensers, will improve the system strength outlook in South-West New South Wales.

The map for 2034/35 suggests that the retirement of thermal power stations such as Vales Point and Eraring will significantly reduce system strength, including in central New South Wales. Improvements in system strength are also expected to occur as a result of new transmission infrastructure planned to be delivered as part of the development of the REZs in northern New South Wales, and the second QNI interconnector. However, as projected additional renewable generation connects to these areas later in the timeframe, and additional coal plant retires, the available system strength will reduce.

1.4.3 Transmission is key to providing resilience in the power system

Figure 1.13: Mean temperature anomalies averaged over Australia between 1910 and 2020 (as calculated from the 1961-1990 average)



Source: Australian Bureau of Meteorology, Annual Climate Statement 2020; Published Jan 2021

The power system will be subject to the changing climate patterns foreseen, as more frequent weather extremes cause increasing operational challenges. **Figure 1.13** illustrates the mean temperature anomalies in Australia over the period from 1910 to 2020. As the trend indicates, increasing temperatures and prolonged heat events can lead to challenging operational issues including difficulties in managing coincident high demand times which may impact the system reliability.

Despite the challenges expected, such as declining minimum demand, strong uptake in distributed PV, need for system strength and inertia and climate changes, the transmission network is still the key to providing a resilient power system. This is particularly important to enable the connection of large block loads such as mines or other industrial loads which are not able to be supplied by the distribution network. **Figure 1.14** illustrates the large spot loads proposed to connecting to the NSW transmission network within the next 10 years. Given their size, these loads are too large to be managed by the existing distribution system without major augmentations.

As a whole, the transmission network plays a leading role in maintaining system stability, and ensuring a reliable and secure power system for NSW.

Figure 1.14: Large spot loads across NSW

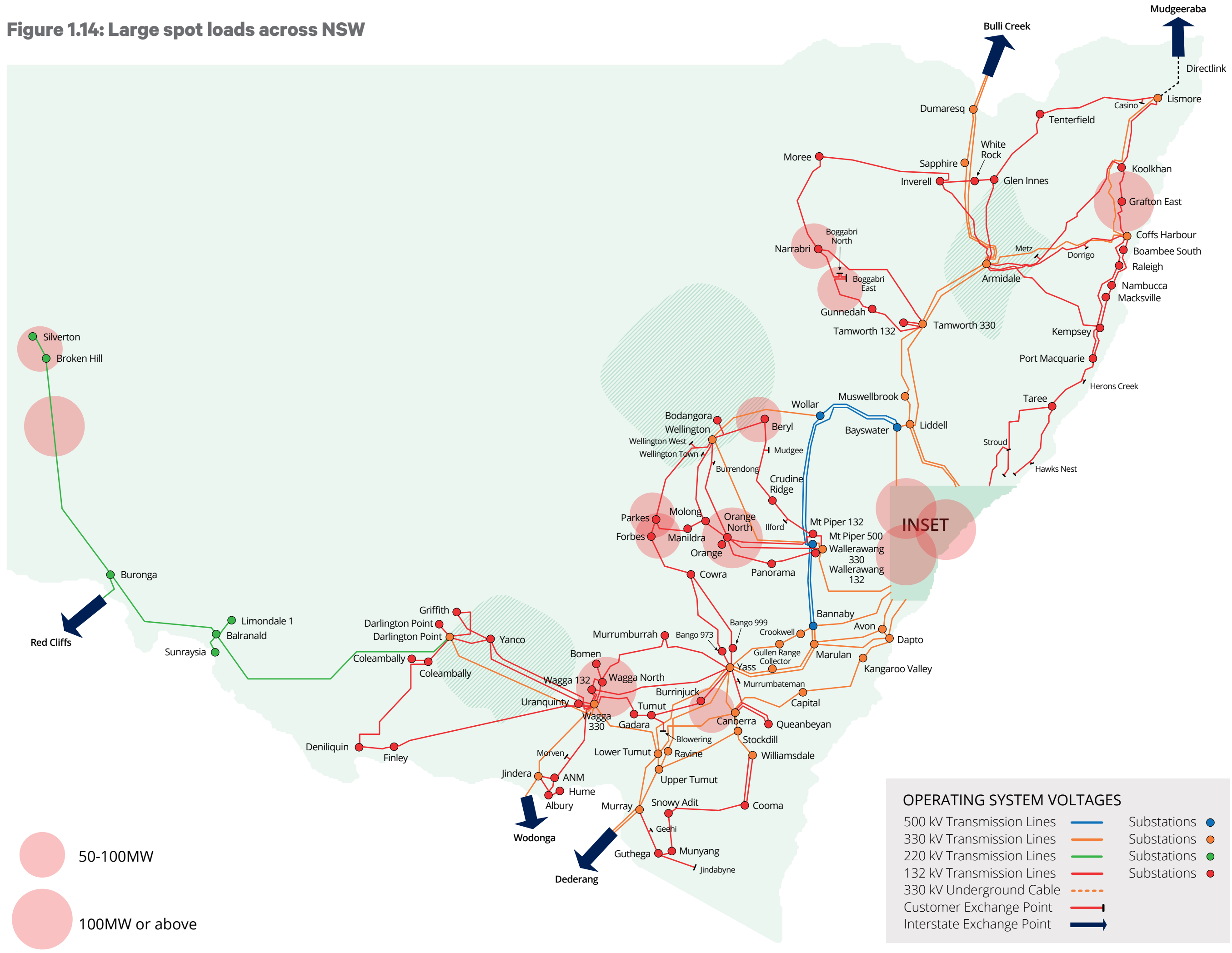
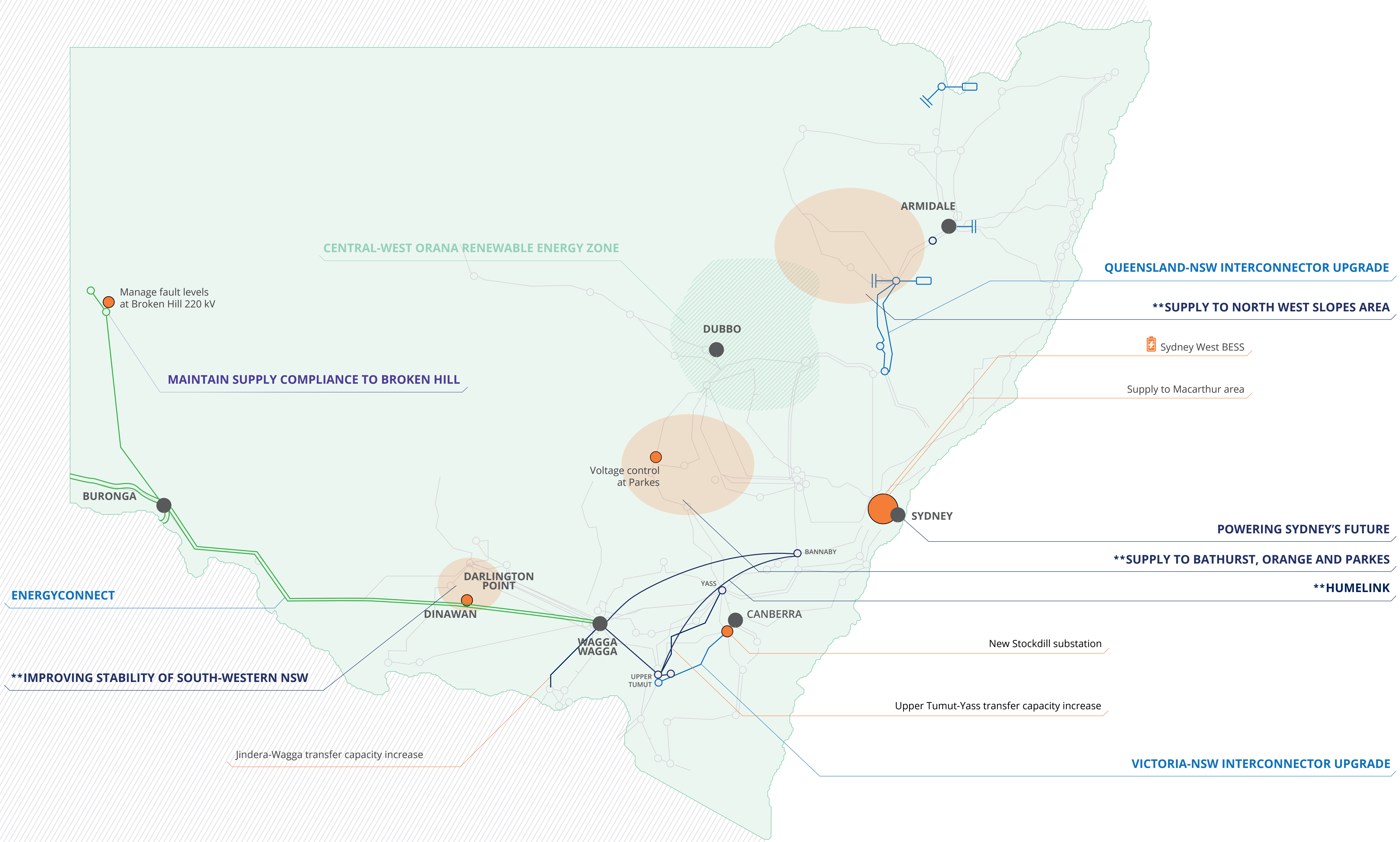
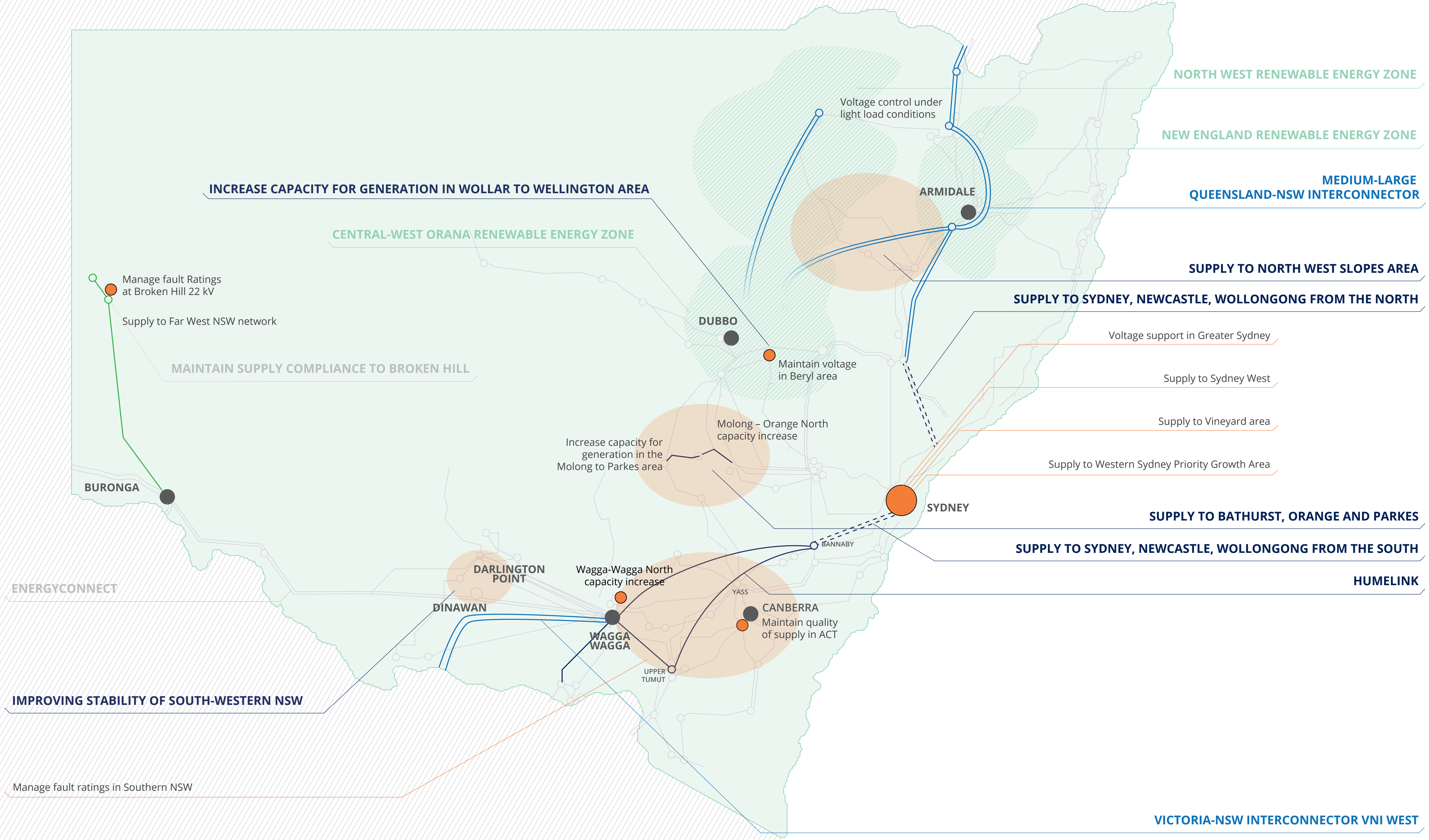


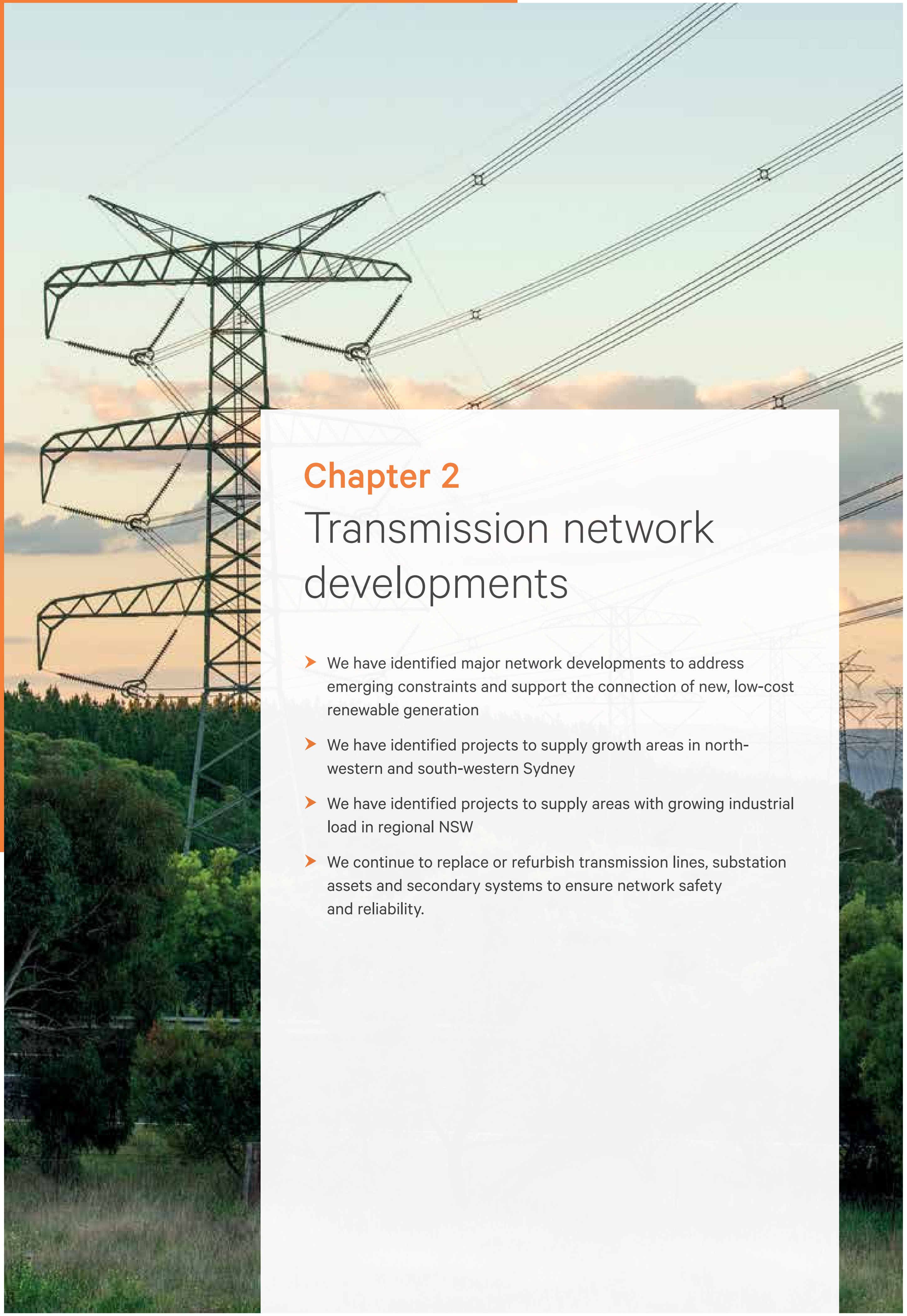
Figure 1.15: Current projects on our network



** These projects are contingent projects currently undergoing the RIT-T process.

Figure 1.16: Future projects on our network





Chapter 2
Transmission network developments

- We have identified major network developments to address emerging constraints and support the connection of new, low-cost renewable generation
- We have identified projects to supply growth areas in north-western and south-western Sydney
- We have identified projects to supply areas with growing industrial load in regional NSW
- We continue to replace or refurbish transmission lines, substation assets and secondary systems to ensure network safety and reliability.

2.1 Proposed major developments

TransGrid has an unprecedented level of generation connection enquiries with over 50,000 MW of potential solar, wind and hydro projects at various stages of development. Most of these enquiries are seeking to connect to remote locations where the existing network capacity is limited.

At the same time, as large baseload generators are projected to retire, the integration of new generation and improvements to interconnection are essential to maintain secure supply and provide effective competition in the wholesale market.

The 2020 ISP published by AEMO provides an independent, strategic view of the efficient development of the NEM transmission network over a 20-year planning horizon. TransGrid proactively monitors the changing outlook for the NSW region and take into consideration the impact of emerging technologies, withdrawal of gas and coal-fired generation and the integration of variable renewable energy (VRE) generation in future transmission plans.

Building on the 2019 NSW Electricity Strategy and the 2018 NSW Transmission Infrastructure Strategy, the NSW Government's Electricity Infrastructure Roadmap was published in December 2020. This is a coordinated framework to deliver a modern electricity system for NSW.

In the 2021 annual planning review, we identified major network developments to address emerging constraints, support the connection of new renewable generation and implement the Roadmap to transition our electricity sector into one that is cheaper, cleaner and more reliable. The projects include:

Committed projects

- Expanding Queensland to NSW transfer capacity (QNI Upgrade);
- Victoria to NSW Interconnector upgrade (VNI Upgrade)

Regulatory consultation completed projects

- A new interconnector between NSW and South Australia (EnergyConnect);

Projects under regulatory consultation

- Reinforcement of the Southern NSW network (HumeLink);
- Victoria to NSW Interconnector West (VNI West);
- Improving stability in South-West NSW;

Planned projects

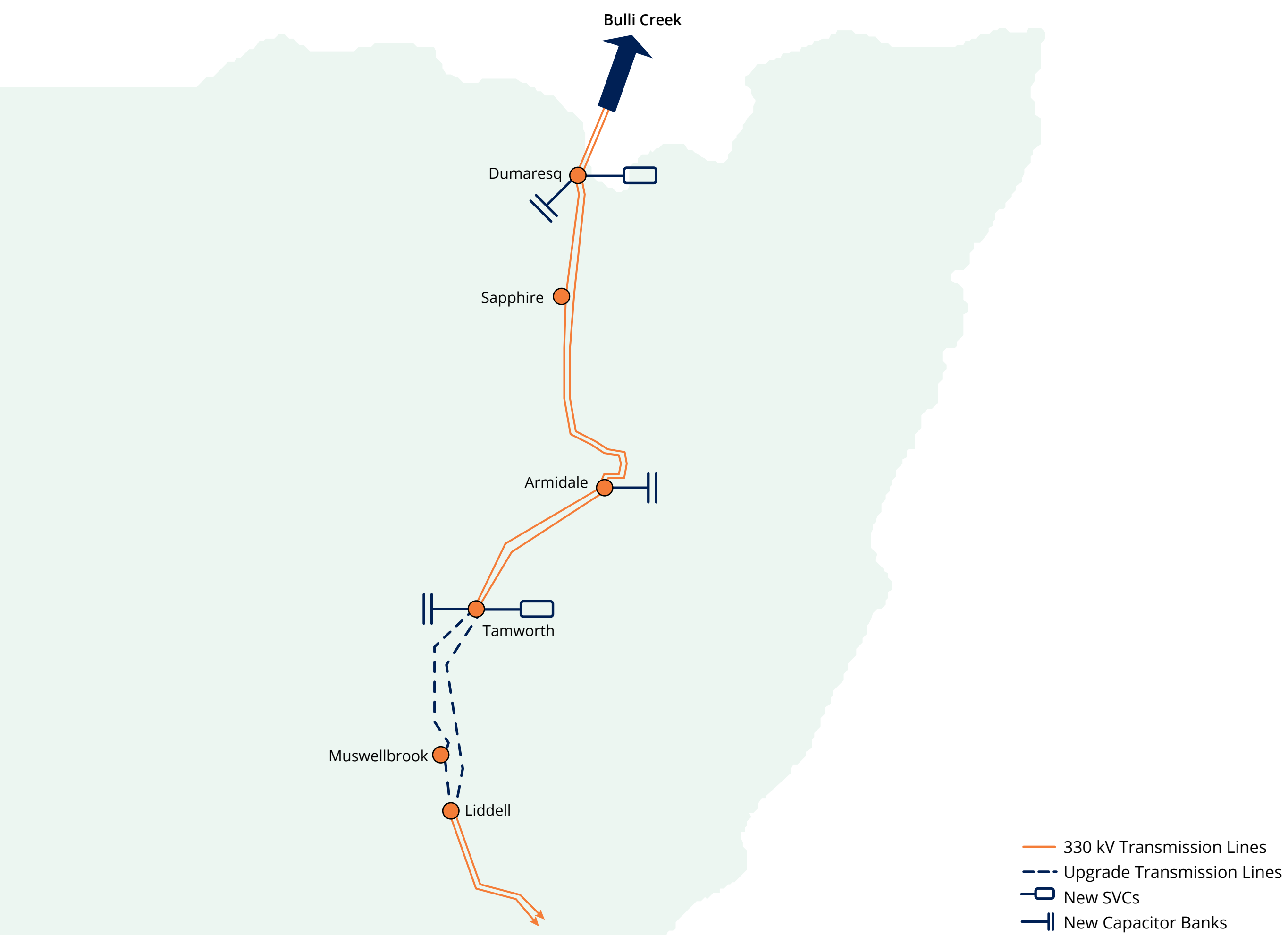
- Central-West Orana Renewable Energy Zone;
- New England Renewable Energy Zone;
- Medium/large Queensland to New South Wales Interconnector;
- North West Renewable Energy Zone; and
- Reinforcement to Sydney/Newcastle/Wollongong load centres.

These major developments are aligned with AEMO's 2020 ISP and NSW Government's Electricity Infrastructure Roadmap. They will provide greater interconnection in the NEM and support or facilitate the connection of large-scale energy zones.

Committed projects

2.1.1 Expanding Queensland to NSW transfer capacity (QNI Upgrade)

Figure 2.1: Minor Queensland to NSW interconnector upgrade



An upgrade to the transmission capacity between New South Wales and Queensland will provide greater access for low-cost generation in Queensland to the southern states. It will also provide additional capacity for new renewable generation in northern NSW, and for generation from the southern states to help meet peak demand in Queensland.

It will:

- Facilitate more efficient sharing of generation across the NEM, thereby avoiding the use of higher cost generators and deferring, or avoiding, the construction of new, more expensive generation and/or storage;
- Continue to provide reliable supply at the lowest cost by deferring the need to build new generation and storage capacity in New South Wales ahead of the forecast retirement of Liddell Power Station; and
- Facilitate the transition to a lower carbon emissions future and the adoption of new technologies through improving access to high quality renewable resources across regions, which further avoids the use of high-cost generators and defers, or avoids, the need to build new generation.

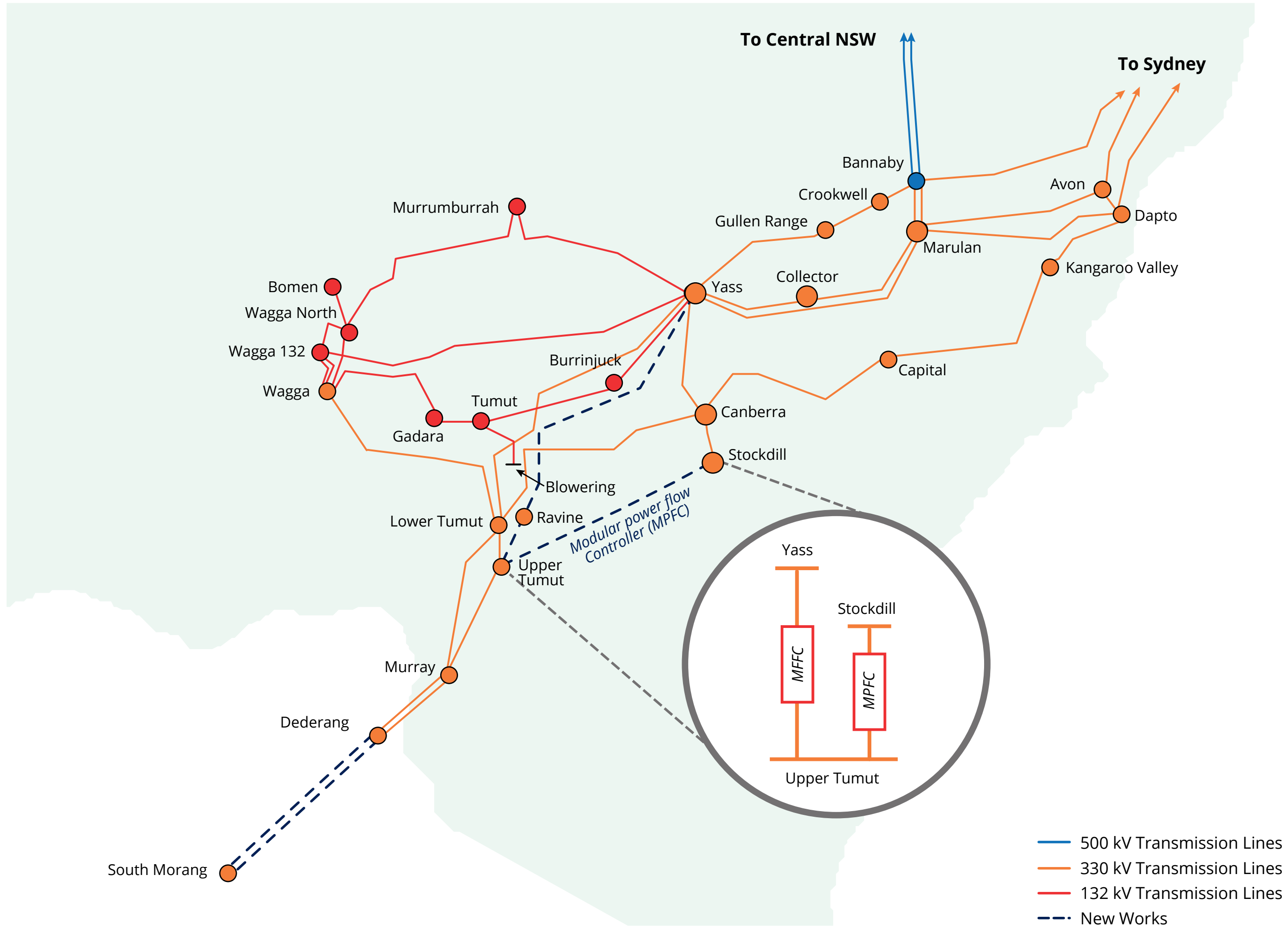
The project includes:

- Uprating the existing 330 kV Liddell to Tamworth lines, and
- Installing new dynamic reactive support at Tamworth and Dumaresq substations and shunt connected capacitor banks at Tamworth, Armidale and Dumaresq substations

QNI Upgrade is identified as a committed ISP project and is expected to be completed by June 2022 at a cost of $217 million.

2.1.2 Victoria to New South Wales Interconnector minor upgrade (VNI Upgrade)

Figure 2.2: VNI Upgrade



An upgrade to the Victoria to New South Wales Interconnector will provide greater access for low-cost generation in Victoria and renewable generation in southern NSW. It will also provide additional capacity for existing peaking generation in southern NSW to meet peak demand in the major load centres of Sydney, Newcastle and Wollongong, at lower cost than building new generation at the major load centres.

The network between southern NSW and Sydney is constrained at times of high demand, and has limited capacity to cater for further generation together with existing generation and import from Victoria to NSW. Thermal capacity constraints between the Riverina, Snowy Mountains and Sydney may limit generation output or import from VIC, as new generation is connected.

The preferred option includes:

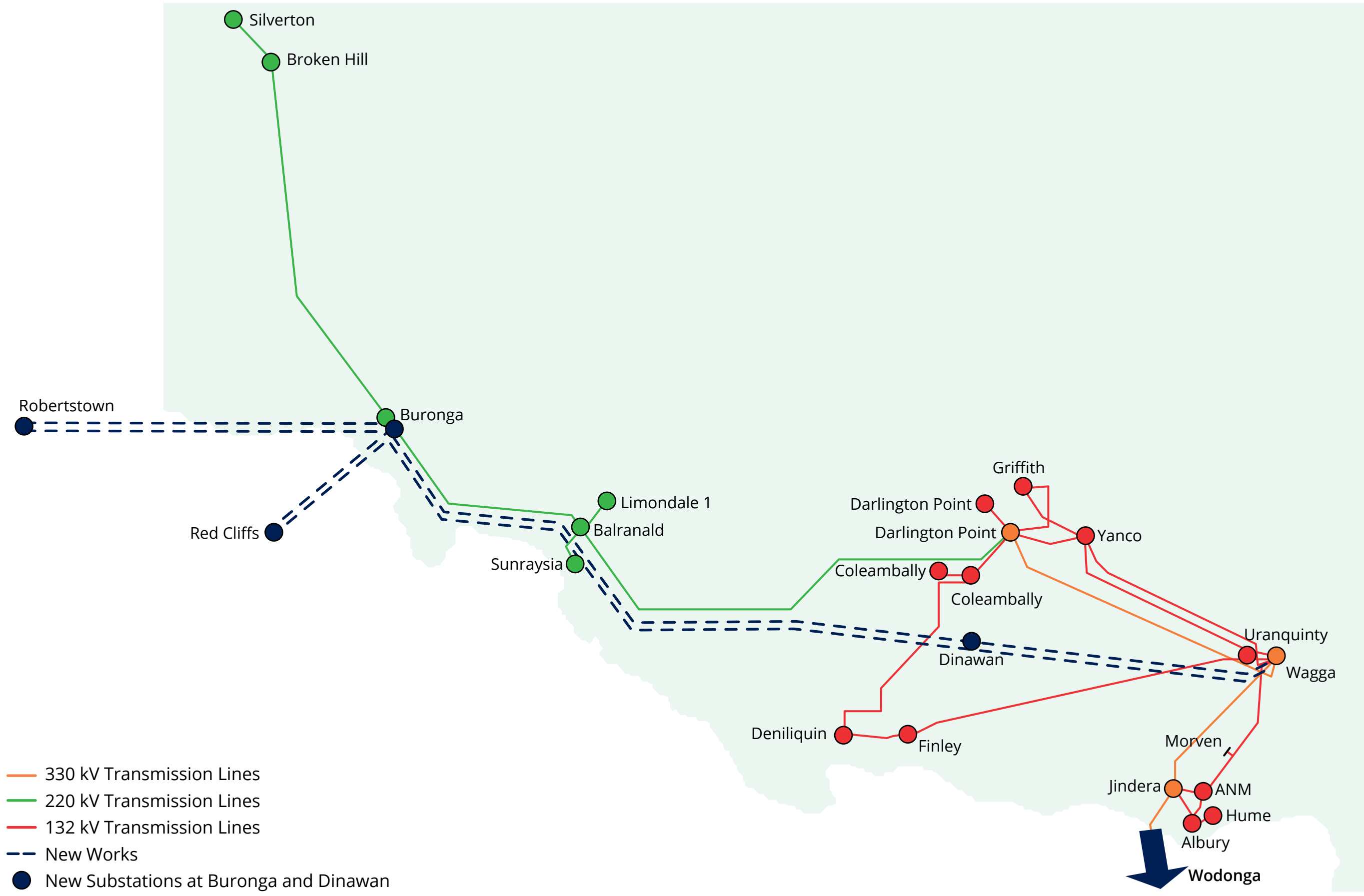
- Installing a new 500/330 kV transformer at South Morang (Victorian works);
- Upgrade the South Morang – Dederang 330 kV lines 1 and 2 to allow operation at thermal rating (Victorian works);
- Install modular power flow controllers on both Canberra – Upper Tumut, and Yass – Upper Tumut 330 kV lines to balance power flows and increase transfer capacity across the region (NSW works).

The indicative increase in capacity of the interconnector option is approximately 170 MW. The VNI Upgrade project is expected to be completed by December 2021 at an estimated cost for the NSW works of $45 million.

Regulatory consultation completed projects

2.1.3 EnergyConnect

Figure 2.3: EnergyConnect



The interconnector between NSW and South Australia (SA) will provide greater access for low-cost renewable energy in SA to supply the eastern states when variable renewable generation in SA is high. It will also allow lower-cost baseload generation in the eastern states to displace higher cost gas-fired generation in South Australia when variable renewable generation in SA is low.

It will also:

- Unlock additional renewable generation resources in the Murray River and Riverland area
- Enhance security of supply for South Australia
- Increase the level of firm contractible capacity and improve market liquidity in South Australia

The scope of the project includes:

- A new 330 kV double circuit line between Robertstown/Bundey (SA) and Buronga (NSW);
- A new 330 kV double circuit line between Buronga and Dinawan;
- A new 330 kV double circuit line between Dinawan and Wagga Wagga;
- A new 330 kV substation at Robertstown, including 275/330 kV transformers at Robertstown/Bundey (SA);
- New 330 kV Phase Shift Transformers (PSTs) at Buronga;
- New 330/220 kV transformers at Buronga;
- New double circuit 220 kV line from Buronga to Red Cliffs in Victoria to replace the existing 220 kV single circuit line;
- Augmentation of existing substations at Robertstown, Buronga, Wagga Wagga and Red Cliffs;
- A new 330 kV switching station at Dinawan;
- Turn in the existing 275 kV line between Robertstown and Para into Tungkillo;
- Static and dynamic reactive plant at Robertstown, Buronga and Dinawan; and
- A Remedial Action Scheme.

The indicative capacity of this interconnector is 800 MW. AER approved the TransGrid and ElectraNet Contingent Project Applications in May 2021 with a total cost of $2.27 billion, of which works in NSW comprise $1.81 billion. The EnergyConnect project is expected to be completed by late 2024[26].

26 TransGrid and ElectraNet – Project EnergyConnect contingent project - AER Final Decision May 2021

Projects under regulatory consultation

2.1.4 Reinforcement of the southern NSW network (HumeLink)

Reinforcement of the southern NSW transmission network would provide access to renewable and peaking generation in southern NSW and Victoria, to meet demand in the major load centres of Sydney, Newcastle and Wollongong at lower cost than building new generation at the major load centres.

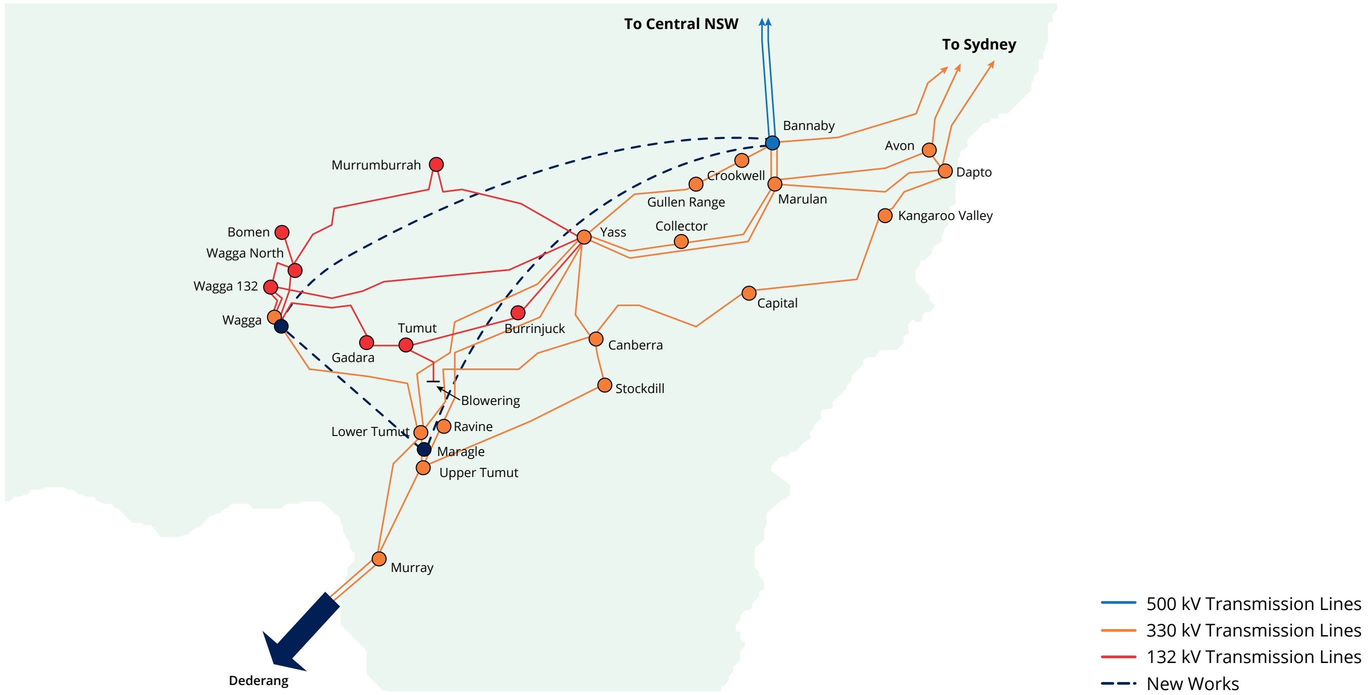
We have applications to connect from renewable generation projects in southern NSW totalling 1,600 MW and pumped hydro at Snowy 2.0 of 2,000 MW. However, the existing transmission capacity between southern NSW and major load centres of Sydney, Newcastle and Wollongong is already heavily utilised at times of peak demand. While the VNI Upgrade will maximise utilisation of the existing assets using modular power flow control devices, these will provide relatively small increases in capacity compared with the generation that has applied to connect. Around 500 MW of existing generation in southern NSW will still be unable to serve the major load centres at peak times.

TransGrid is investigating options to reinforce the NSW southern shared network to increase transfer capacity to the state's major load centres of Sydney, Newcastle and Wollongong. This would:

- Increase the transfer capacity and stability limits between the Snowy Mountains and major load centres of Sydney, Newcastle and Wollongong;
- Enable greater access to lower cost generation to meet demand in these major load centres; and
- Facilitate the development of renewable generation in high quality renewable resource areas in southern NSW as well as southern states, which will further lower the overall investment and dispatch costs in meeting NSW demand whilst also ensuring that emissions targets are met at the lowest overall cost to consumers.

The Project Assessment Draft Report (PADR), published in January 2020, found that a 500 kV option between Maragle, Wagga Wagga and Bannaby provides the greatest net market benefit and is the preferred option.

Figure 2.4: HumeLink preferred option



The high level scope includes:

- New Wagga Wagga 500/330 kV Substation and 330 kV connection to the existing Wagga Wagga Substation
- Three 500 kV transmission lines:
  - Between Maragle and Bannaby 500 kV Substation,
  - Between Maragle and Wagga Wagga 500 kV Substation, and
  - Between Wagga Wagga and Bannaby 500 kV Substation
- Three new 500/330/33 kV 1,500 MVA transformers at Maragle Substation and two new 500/330/33 kV 1,500 MVA transformers at new Wagga Wagga Substation
- Augment the Maragle Substation to accommodate the additional transmission lines
- Augment the existing Substations at Wagga Wagga and Bannaby to accommodate the additional transmission lines/transformers.

HumeLink is identified as an actionable ISP project. The PACR is expected to be published in Q3 2021.

2.1.5 Victoria to New South Wales Interconnector West (VNI West)

Additional interconnection between NSW and Victoria would help maintain reliability of supply in Victoria, as Victorian coal-fired generators are scheduled to retire in the late 2020s and the 2030s. It would mitigate reliability risks associated with diminishing reliability of the existing coal fleet ahead of their scheduled retirements, and provide insurance against unexpected early plant closures. A western route for additional interconnection would also provide a significant increase in capacity for low-cost renewable generation in south-western NSW and north-western Victoria.

The market benefits of additional interconnection come from:

- Efficiently maintaining supply reliability in Victoria following the closure of further coal-fired generation and the decline in ageing generator reliability – including mitigation of the risk that existing plant closes earlier than expected
- Facilitating efficient development and dispatch of generation in areas with high quality renewable resources in Victoria and southern NSW through improved network capacity and access to demand centres
- Enabling more efficient sharing of resources between NEM regions.

AEMO and TransGrid are jointly undertaking a RIT-T to assess the technical and economic viability of expanding the interconnector capacity between Victoria and New South Wales, to identify the preferred option to meet the identified need and its optimal timing.

The options proposed to meet the identified need include:

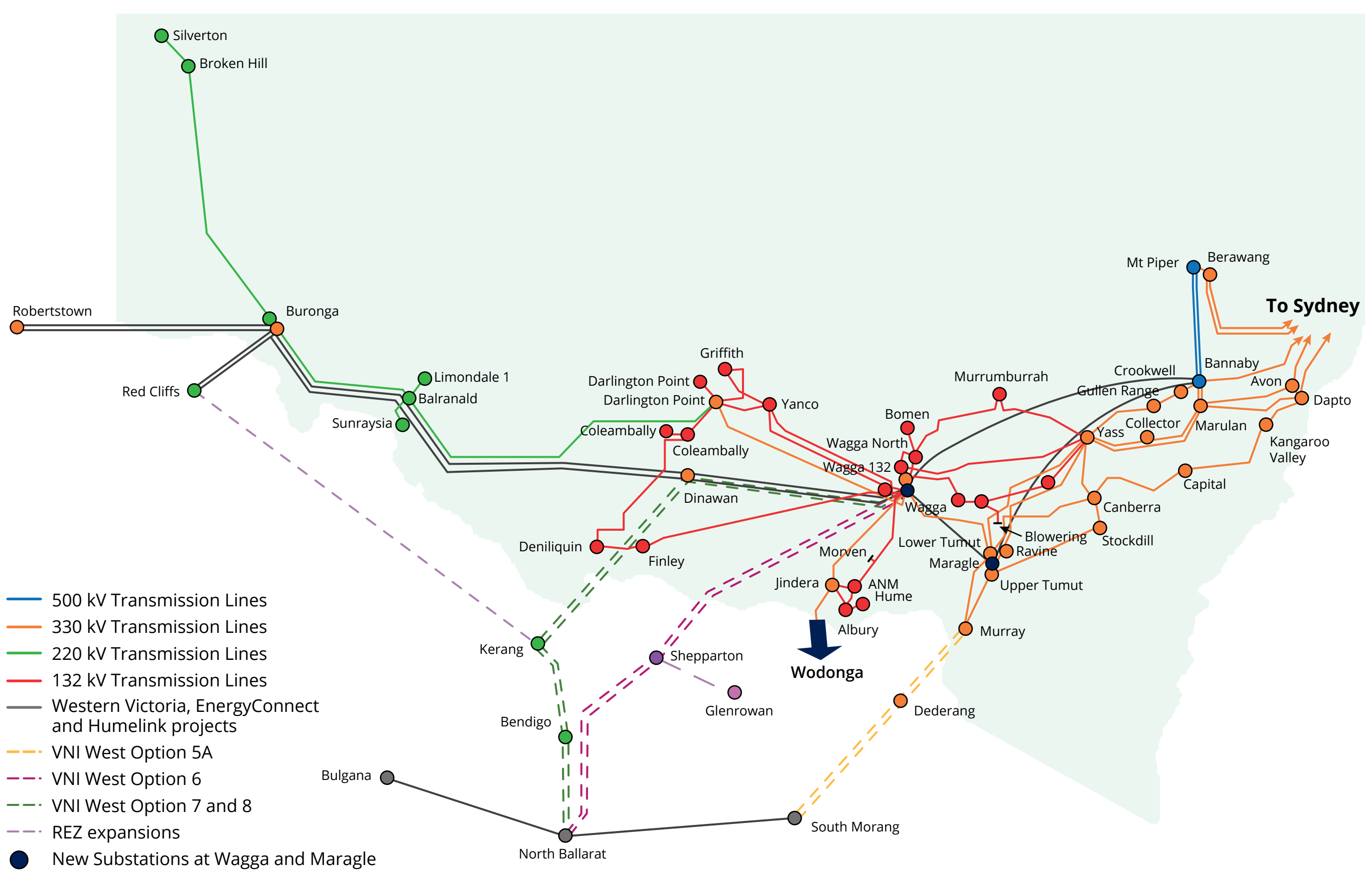
- New 330 kV transmission from South Morang via Dederang to Murray
- New 500 kV transmission from North Ballarat via Bendigo and Shepparton to Wagga Wagga
- New 500 kV transmission from North Ballarat via Bendigo, Kerang and Dinawan to Wagga Wagga
- New 330 kV transmission lines from North Ballarat via Kerang and Dinawan to Wagga Wagga.

Potential expansions to accommodate renewable energy connections are also being considered:

- Expansion A: New transmission lines to unlock generation capacity from Kerang to Red Cliffs
- Expansion B: New transmission lines to unlock generation capacity from Shepparton to Glenrowan.

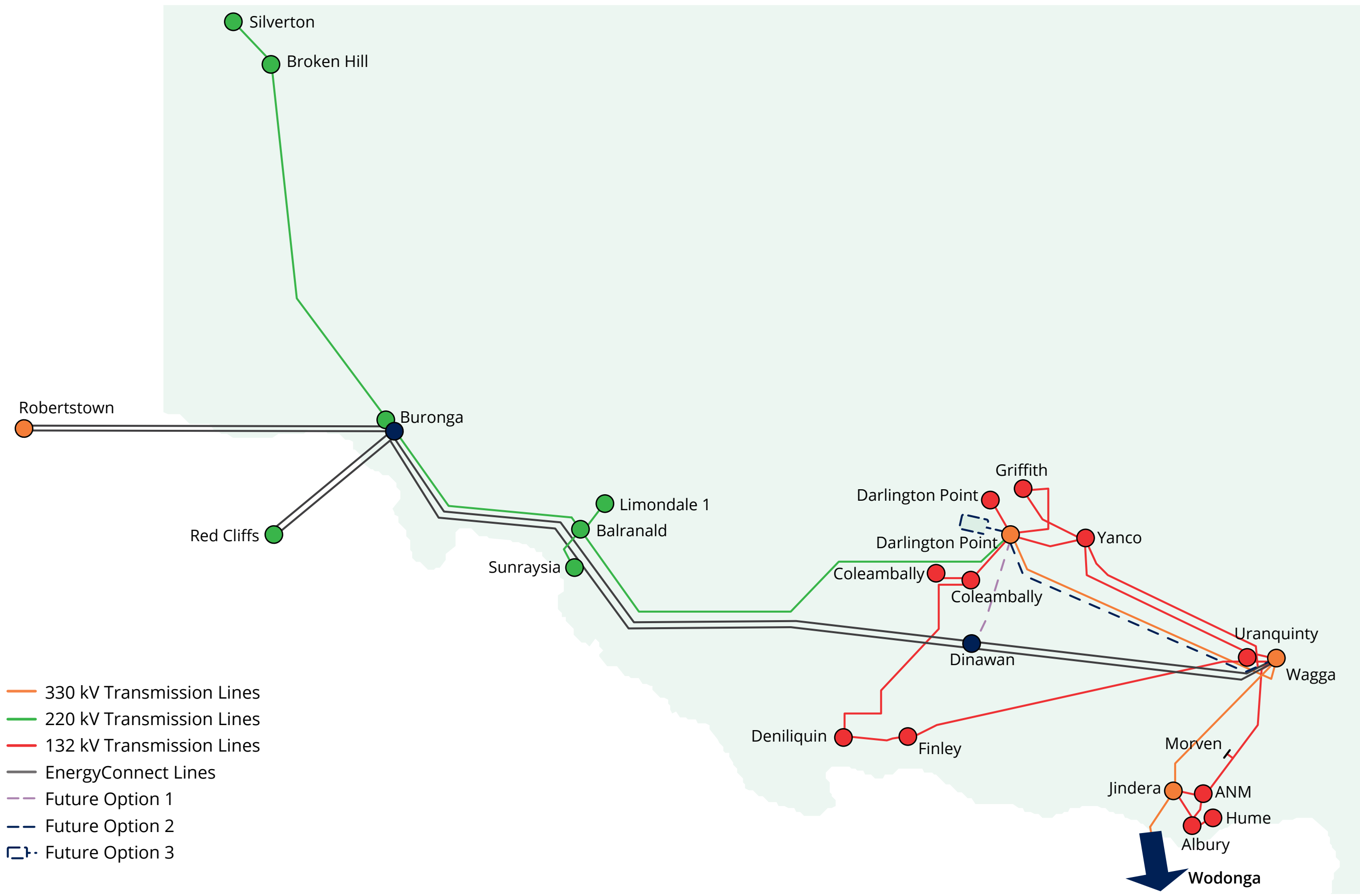
VNI West is identified as an actionable ISP project with decision rules that allow for adaptation if circumstances change. AEMO and TransGrid are jointly progressing activities to publish a PADR under the actionable ISP framework by December 2021.

Figure 2.5: VNI West Credible Options



2.1.6 Improving stability in South-West NSW

Figure 2.6: South-West NSW network



There is an opportunity to increase the level of renewable generation that can be integrated in south-west NSW by improving voltage stability. This will address a constraint on flows in an easterly direction on the 330 kV transmission line from Darlington Point towards Wagga Wagga (63 Line).

The main power system in south western NSW consists primarily of a 330 kV transmission line from Darlington Point to Wagga Wagga (63 Line) and 220 kV transmission lines west of Darlington Point (including X5 Line). Smaller underlying 132 kV transmission lines supply regional towns.

The 132 kV system in south western NSW can experience significant stability issues during an outage of 63 Line. These have historically been prevalent during high power flows west from Wagga Wagga, and managed operationally. Power flows east towards Wagga Wagga have not been high enough to cause stability issues during an outage of 63 Line.

The commissioning of new generation in south western NSW has resulted in high power flows east towards Wagga Wagga from mid-2020. Under these conditions, the 132 kV system experiences more significant stability issues during an outage of 63 Line. In particular, there is a risk of fast voltage collapse which would result in power electronics-based generation becoming unstable.

New operational measures have been implemented to maintain power system stability during high easterly power flows. Considering the very fast timeframe of voltage collapse, AEMO has recently implemented a constraint in the NEM Dispatch Engine (NEMDE) to limit power flows on 63 Line to approximately 300 MW (varying slightly with power system conditions). About 800 MW of renewable generation is being commissioned in south-west NSW at present. This line 63 constraint will result in material constraints to generation in the region under normal power system conditions.

TransGrid is considering options to alleviate this constraint:

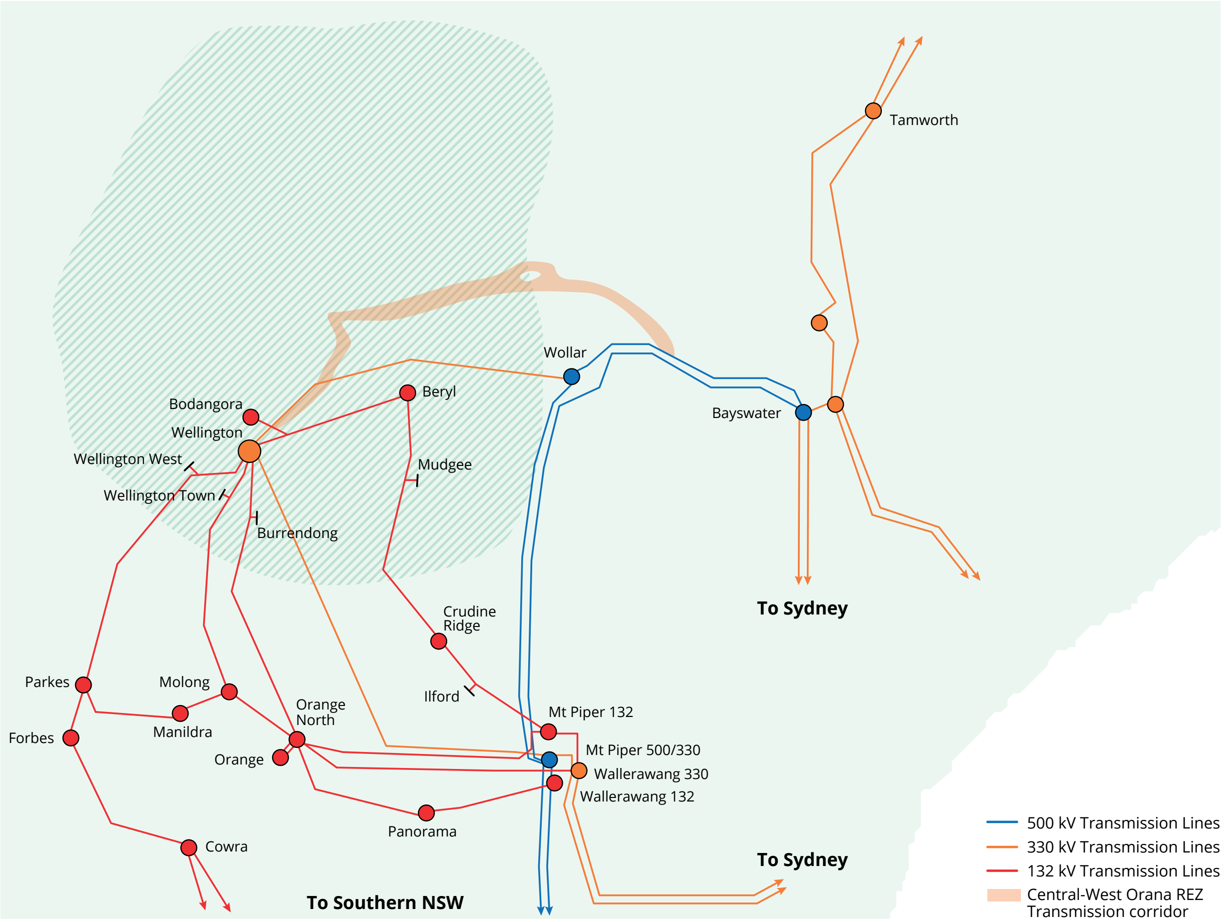
- Two variants of a new transmission line between Darlington Point and Dinawan substations;
- A new transmission line between Darlington Point and Wagga Wagga; and
- Alternative technologies such as a static synchronous compensator (STATCOM) or Grid Forming Battery Energy Storage solution
- Enhanced special protection and control schemes.

A project to alleviate this constraint will deliver market benefits through relieving existing and forecast constraints on generation in south-west NSW. The Project Assessment Draft Report (PADR), will be published in Q3 2021.

Planned Projects

2.1.7 Central-West Orana Renewable Energy Zone

Figure 2.7: Central-West Orana Renewable Energy Zone



The Central-West Orana Renewable Energy Zone (REZ) will facilitate scale-efficient development and integration of low-cost renewable generation into the power system. Announced by the NSW Government in late 2019, the Central-West Orana REZ is the first pilot REZ to be rolled out under the NSW Government's Electricity Strategy and NSW Electricity Infrastructure Roadmap.

The REZ will enable at least 3,000 MW of new electricity capacity in the State's Central-West Orana region, bringing up to $5.2 billion in private investment to the local region. The pilot REZ will inform the development of other REZs.

The Central-West Orana region was chosen for the pilot REZ because it benefits from relatively low transmission build costs due to its proximity to the existing backbone transmission network, a strong mix of energy resources and significant investor interest. In 2020 the NSW Government received 113 registrations totalling 27 gigawatts of generation and storage in and around the REZ, in response to a call for expressions of interest.[27]

TransGrid is working with the NSW Government to plan new transmission lines, substation(s) and related infrastructure to support the delivery of the Central-West Orana REZ.

Released in December 2020, the study corridor for the Central-West Orana REZ Transmission (Transmission project) runs north-west from the existing 500 kV network near Merriwa, passing south of Dunedoo before connecting to the existing network east of Wellington. The corridor also includes an option to extend further south to near Lake Burrendong.

TransGrid is meeting and working with landowners and local communities to discuss constraints and opportunities within the study corridor, including carrying out environmental surveys to help with informing route identification.

Key benefits of the Transmission project include:

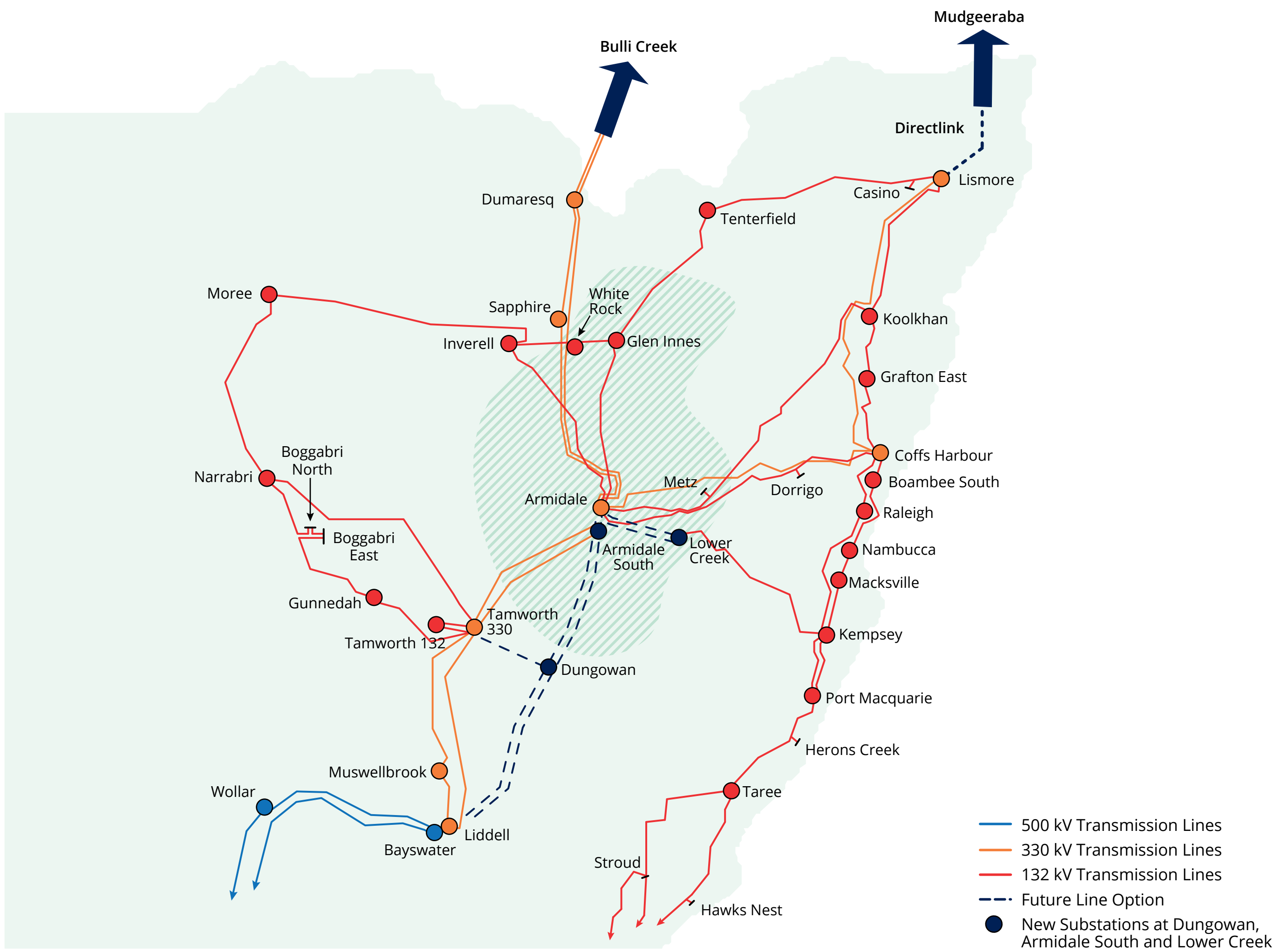
- Lower wholesale electricity costs – placing downward pressure on customer bills through increased competition;
- Improved reliability - by delivering large amounts of new energy supply
- New local jobs – opportunities for local workers and businesses during construction
- Reduced emissions and a greater mix of renewable energy in the National Electricity Market, supporting Australia's transition to a lower carbon future.

The Transmission project is identified in the 2020 ISP as an actionable project. It is anticipated that regulatory approval of cost recovery for the Transmission project will be determined pursuant to the proposed Transmission Efficiency Test that is being developed for the NSW Electricity Infrastructure Roadmap.

27 https://energy.nsw.gov.au/renewable-energy-zone-sparking-investment-boom, accessed 26 June 2020.

2.1.8 New England Renewable Energy Zone

Figure 2.8: New England Renewable Energy Zone



The New England REZ will facilitate scale-efficient development and integration of low-cost renewable generation into the power system. The REZ forms part of the NSW Electricity Infrastructure Roadmap, and will provide new generation ahead of the retirement of coal-fired generators in NSW.

TransGrid has received significant ongoing interest from renewable energy proponents seeking to connect to the network in this area.

Presently, there is approximately 460 MW of renewable generation connected in the area. A further 830 MW is committed to connect and more than 1,550 MW is at an advanced stage in the connection process.

However, the limited capacity of the existing 330 kV and 132 kV networks will result in output limitation of connecting generators as the generation in the area increases. Increasing transmission capacity would maximise the existing renewable energy generation opportunities and facilitate new generator connections in the New England area.

Benefits would be derived from:

- Lower costs to meet the reliability standard for NSW, by enabling access to the output from additional generation connections; and
- Lower market dispatch costs (and hence lower cost to consumers).

The project may be accelerated through NSW Government policy[28] and may be staged if required to maximise economic benefits.

New England REZ is identified as a future ISP project.

28 New South Wales Government. New England to light up with second NSW Renewable Energy Zone, at https://www.nsw.gov.au/media-releases/new-england-to-light-up-second-nsw-renewable-energy-zone.

2.1.9 Medium/large Queensland to New South Wales Interconnector

Figure 2.9 QNI Medium and Large

We are investigating the potential benefits of further increases to transmission capacity between NSW and Queensland, beyond the capacity provided by the QNI Minor Upgrade.

Additional transmission capacity would need to deliver net market benefits, which could come from:

- Efficiently maintaining supply reliability in NSW following the closure of further coal-fired generation and the decline in ageing generator reliability
- Facilitating efficient development and dispatch of generation in areas with high quality renewable resources in northern NSW through improved network capacity and access to demand centres
- Enabling more efficient sharing of resources between NEM regions.

Options to deliver these benefits include:

- A "virtual transmission line" comprised of grid-scale batteries on both sides of a constraint (for bidirectional limit increases), or a grid-scale battery on one side and braking resistor on the other side (for unidirectional limit increases)
- Transmission lines at 500 kV or 330 kV from southern Queensland to Armidale South and from Armidale South to CWOREZ via Boggabri.

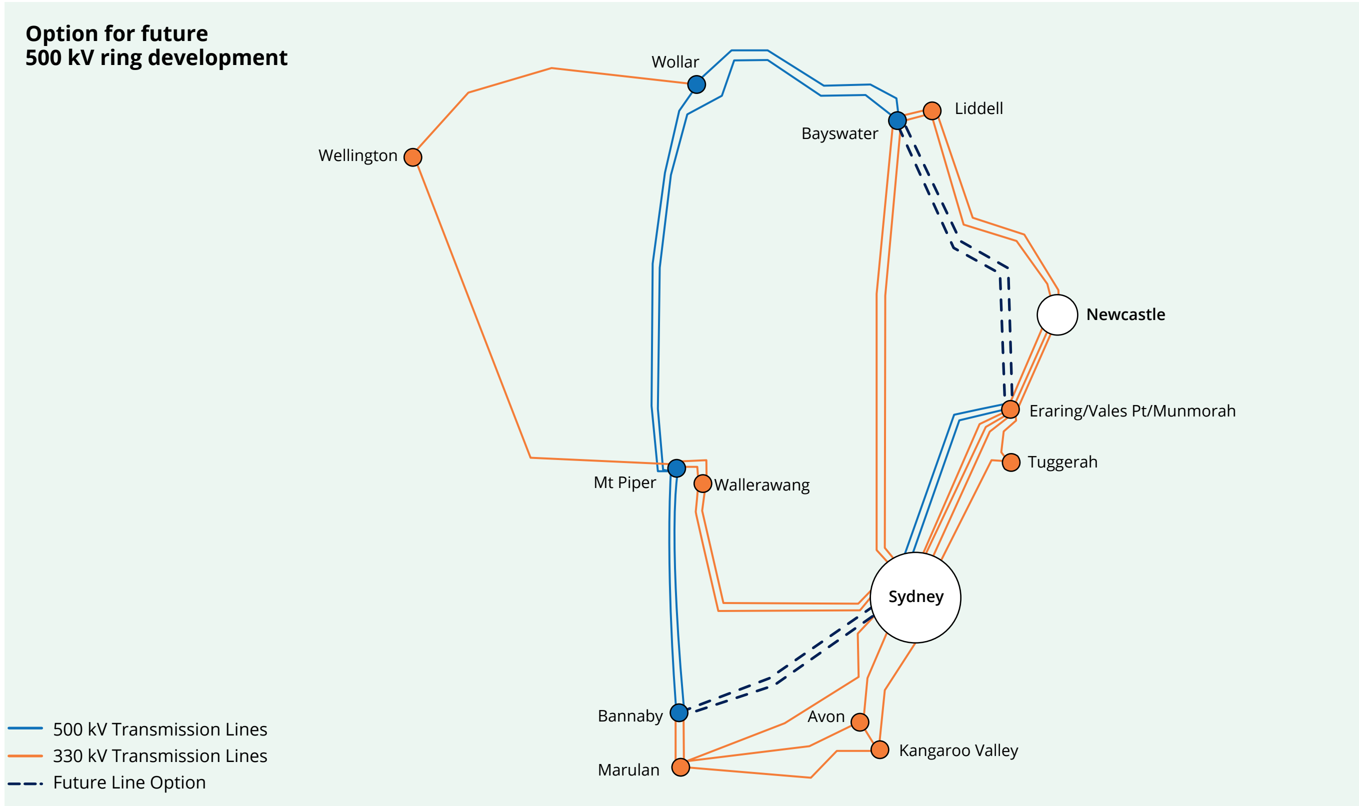
These options can be optimised with capacity to the New England REZ discussed in **Section 2.1.8**, and can be staged by geography, operating voltage and number of circuits to maximise net economic benefits.

Following the development of a medium QNI upgrade, a larger QNI upgrade could be needed to increase the capacity of the network to host renewable energy and share both storage and firming services between the regions. This larger upgrade will depend on future generation developments and retirements in Queensland and NSW.

The medium or large QNI upgrade is identified as a future ISP project.

2.1.10 Reinforcement to Sydney/Newcastle/Wollongong load centres

Figure 2.10: Reinforcement to Sydney/Newcastle/Wollongong load centres



The Sydney, Newcastle and Wollongong area includes significant urban, commercial and industrial loads that comprise about three quarters of the demand for electricity in NSW.

When power stations at Vales Point and Eraring on the Central Coast retire, it is expected that future demand will be met by the generation outside of the load area. Therefore, there will be a need to increase the capacity from regional NSW to the major load centres. The network reinforcements are expected to be achieved through further development of the 500 kV ring between the Upper Hunter, Central West, Southern Tablelands and Sydney, Newcastle and Wollongong.

In future, the transmission capability within the core NSW network will be mainly determined by the thermal capacity of:

- The 330 kV transmission lines between power stations in the Upper Hunter (Liddell and Bayswater) and the Central Coast; and
- The 330 kV transmission lines from Bannaby to Sydney and the south coast.

Two sections of the 500 kV ring remain to be developed, as shown in **Figure 2.10.** They are:

- A double circuit 500 kV line between the Upper Hunter and Central Coast, which can also be connected in the Newcastle area at a later date; and
- A double circuit 500 kV line between Bannaby and Sydney.

The need and timing for both 500 kV sections are subject to the retirements of Vales Point and Eraring Power Stations or development of renewable generation in regional NSW beyond the Central-West Orana REZ Stage 1.

This project is identified as a future ISP project.

2.1.11 North West Renewable Energy Zone

The North West REZ will facilitate scale-efficient development and integration of low-cost renewable generation into the power system. TransGrid has received around 2,000 MW connection interest from solar farm proponents seeking to connect to the network in this area and the existing transmission network has only 132 kV transmission lines.

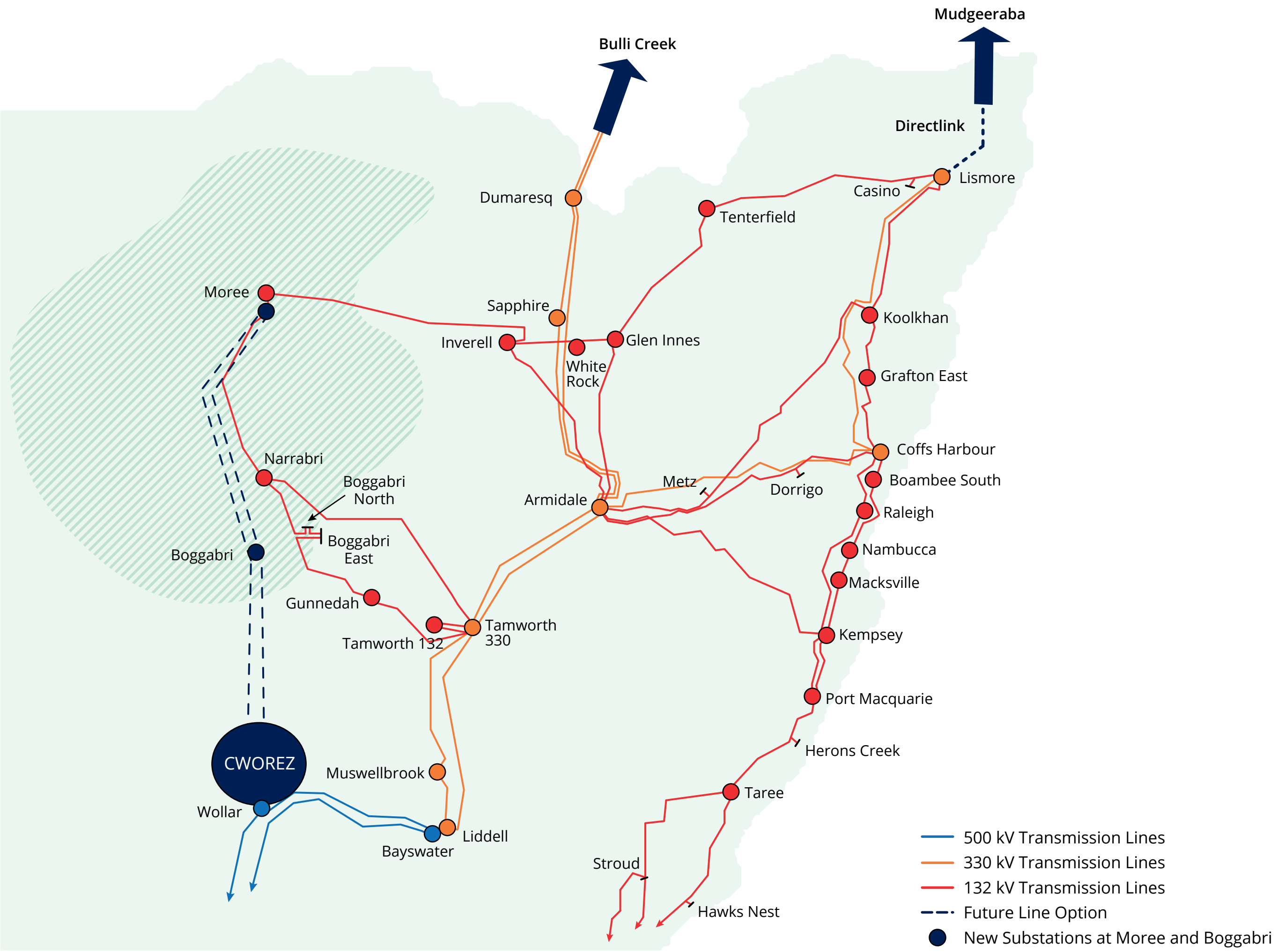
The limited capacity of the existing 132 kV networks will result in output limitation of connecting generators as the generation in the area increases. Increasing transmission capacity would maximise the existing renewable energy generation opportunities and facilitate new generator connections in the north western NSW area.

Benefits would be derived from:

- Lower costs to meet the reliability standard for NSW, by enabling access to the output from additional generation connections; and
- Lower market dispatch costs (and hence lower cost to consumers).

North West REZ is identified as a future ISP project.

Figure 2.11 North West Renewable Energy Zone



2.2 Forecast of constraints

The NER Clause 5.12.2(c)(3) requires reporting the forecast of constraints and inability to meet the network performance requirements set out in the NER Schedule 5.1 or relevant NSW legislations or regulations over one, three and five years. The above information has been set out in this Chapter. TransGrid has provided additional connection point and transmission line data, on an external website. To access this information go to the TransGrid website and navigate to the Transmission Planning page at:

https://www.transgrid.com.au/what-we-do/Business-Planning/transmission-annual-planning/Pages/default.aspx

TransGrid's Network Planning function analysed the expected future operation of its transmission networks over a 10 year period, taking into account the relevant forecast loads, any future generation, market network services, demand side and transmission developments and any other relevant data to determine the anticipated constraints over one, three and five years.

TransGrid's Network Planning group conducts its annual planning review which includes the following activities:

- Incorporation of the forecast loads as submitted or modified by relevant registered participants in accordance with the NER Clause 5.11.1;
- A review of the adequacy of existing connection points and relevant parts of the transmission system, and planning proposals for future connection points;
- Taking into account the most recent AEMO system planning updates, including the 2020 ISP, the National Transmission Network Development Plan, and the issue of the 2020 System Strength and Inertia Report;
- Consideration of the potential for augmentations, or non-network alternatives to augmentations, that are likely to provide a net economic benefit to all those who produce, consume and transport electricity in the market;
- Consideration of the condition of network assets; and
- Consideration of the potential for replacements of network assets, or non-network options to replacements of network assets, that are likely to provide a net economic benefit to all those who produce, consume and transport electricity in the market.

These activities form the basis by which TransGrid reviews and updates the forecast constraints information provided in this report.

2.3 Subsystem developments

This section describes TransGrid's capital works that are proposed to address specific areas or regional network needs. The information provided in this section describes the work, the actual or potential constraint or inability to meet network performance requirements of the NER Schedule 5.1, the need or proposed operational date, the proposed solution and its cost estimate.

These augmentation works do not cause any material inter-network impact as they address localised or site specific needs within each region. In assessing whether an augmentation to the network will have a material inter-network impact TransGrid has examined if its proposed works will impose power transfer constraints within other Transmission Network Service Provider (TNSP) networks or adversely impact the quality of supply in other TNSP networks.

The information in this section also includes ongoing and recently completed replacement works to provide an integrated overall view of capital expenditure requirements within an area.

Planned projects included in the subsystem developments are aligned with the expenditure allowance approved in the AER's final determination for the 2018/19-2022/23 revenue period, also included are planned projects in the next regulatory period. TransGrid considered credible network and non-network options to address the actual or potential constraints or the inability to meet network performance requirements. This includes the use of interconnectors with other regions, generation options, demand side options, market network service options and inter-network options.

The proposed subsystem developments outlined in this section, covering augmentation and replacement works align with the primary objectives of AEMO's ISP and National Transmission Network Development Plan, those being:

- Enhancing interconnection capacity between NSW and the other states;
- Supporting the development and connection of large-scale renewable energy zones across the NEM; and
- Improving system strength and security in response to the decline of thermal generation sources and the increase in renewable energy sources, particularly in NSW and Victoria.

The information reported in this section meets the requirement of the NER Clause 5.12.2(c)(5) and (6).

TransGrid presently does not anticipate any additional subsystem development network investment beyond that given in the following sections, based on current planning information and requirements.

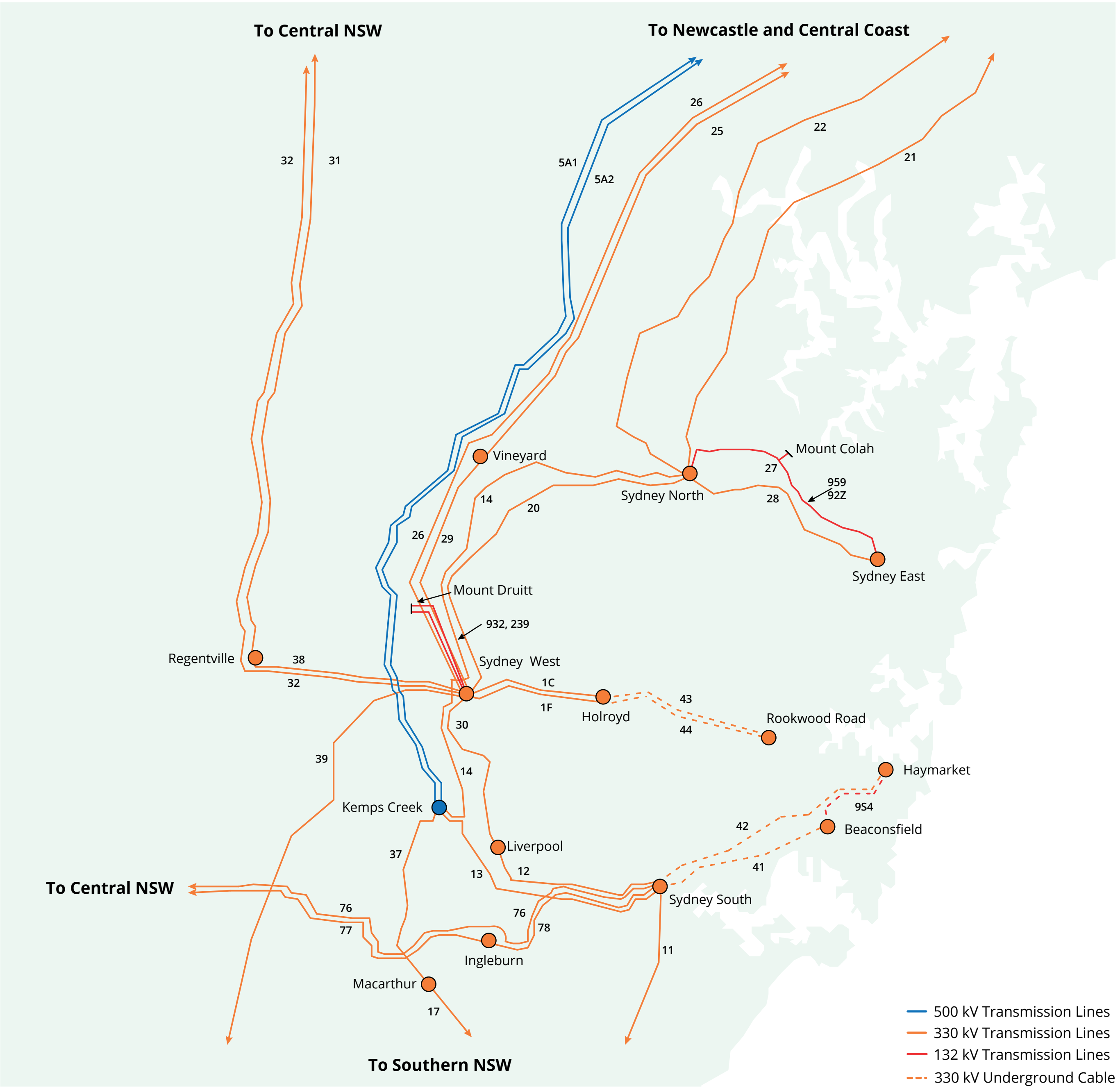
2.3.1 Greater Sydney

The Greater Sydney area includes the Central Business District (CBD) of Sydney which is the largest hub in Australia for economic activity, major transport infrastructure, industry and tourism. Increasingly, the Inner Sydney area is also home to a growing number of people attracted to shorter commutes and access to entertainment and recreation offered by the central Sydney precincts and the Sydney Harbour foreshore.

The Inner Sydney area also provides a base for a number of major infrastructure and transport networks including road tunnels, airports, ports, train networks and data centres. These entities require a high level of electricity reliability and security to maintain services required for Sydney to operate as a major international city. Many of these entities are currently implementing large developments or expansion plans, with many projects under construction or scheduled for the near term.

The following figure shows the Greater Sydney network, including transmission supplies to the area.

Figure 2.12: Greater Sydney network



Planned projects

The table below provide a list of planned augmentation projects to address forecast load growth and connect new distribution zone substations in the Greater Sydney area.

Low-cost investment opportunities that may deliver economic benefits or improve system security have also been identified.

Table 2.1: Planned projects in Greater Sydney

Project description	Planned date	Total cost ($million April-21)	Purpose and possible other options	Project justification
Installation of one 132 kV switchbay at Sydney West 330/132 kV Substation	2021	2.7	For connection of Endeavour Energy's planned South Erskine Park Zone Substation to meet load growth in Western Sydney Employment Area. Refer to Endeavour's DAPR for more details.	Load driven
Installation of two 132 kV switchbays at Sydney West 330/132 kV Substation	2022	3.6	For connection of Endeavour Energy's supply to a new data center load near Sydney West substation. Refer to Endeavour's DAPR for more details.	Load driven
Installation of one 330/66 kV transformer at Macarthur 330/132/66 kV Substation	2022	8.7	To address a capacity constraint in the Nepean area that has arisen from 2018. Temporary load transfers in the Endeavour Energy network are being enacted to defer the need date.	Load driven
Installation of one 132 kV switchbay at Vineyard 330/132 kV Substation	2023	2	For connection of Endeavour Energy's planned Box Hill Zone Substation, to supply a new urban development at Box Hill. Refer to Endeavour's DAPR for more details.	Load driven
Strategic property acquisition for Western Sydney Priority Growth Area	2023	19	To strategically purchase the land south of TransGrid's Kemps Creek 500/330 kV Substation for a new Bulk Supply Point at Kemps Creek.	Strategic Property
Maintain the voltage stability at Vineyard BSP	2024	40.7	To address the voltage stability issue at Vineyard 330/132 kV substation due to the load growth in North-western Sydney region.	Load driven
Strategic easement acquisition for supply to Sydney from the south	2024	TBA	To strategically obtain an easement in the Western Sydney area to cater for a future new transmission supply from southern NSW to Sydney.	Strategic Property
Sydney West BSP Supply	2024	20	To address the network constraints due to overloading of Sydney West 330/132 kV transformer under N-1 contingency.	Load driven
Supply to Western Sydney Priority Growth Area	2025	80	There is a number of options being explored including, a new bulk supply point to be adjacent to TransGrid's Kemps Creek Substation. The bulk supply point will support load growth in the Western Sydney region, including new residential and commercial precincts.	Load driven
Bayswater to Sydney West 330 kV smart grid controls	2025	3	Installation of a remedial action scheme to protect against trips of two or more of the following 330 kV lines: Bayswater to Regentville (31), Bayswater to Sydney West (32) and Regentville to Sydney West (38). For multiple circuit trips, the scheme will run back generation and load to avoid cascading outages and further loss of load in the Greater Sydney area.	Economic benefits
Sydney northwest 330 kV smart grid controls	2025	3	Installation of a remedial action scheme to protect against trips of two or more of the following 330 kV lines: Sydney North to Tuggerah (21), Sydney North to Vales Point (22), Vineyard to Eraring (25), Sydney West to Tuggerah (26) and Munmorah to Tuggerah (2M). For multiple circuit trips, the scheme will run back generation and load to avoid cascading outages and further loss of load in the network.	Economic benefits
Reactor Reactive support in the Greater Sydney Region	2026	10	To address the high voltage issues during low demand period in Ausgrid distribution network. The installation location will be optimised within Greater Sydney region.	Voltage control

Project description	Planned date	Total cost ($million April-21)	Purpose and possible other options	Project justification
Facilitate Ausgrid connection works at Beaconsfield Substation.	2028	0.4	This project is to facilitate Ausgrid's replacement of 132 kV feeder 9SA and 92P Beaconsfield to Campbell Street and Belmore Park. Refer to Ausgrid's DAPR for more details.	Joint planning
Vineyard BSP Supply	2028	15.2	To address the network constraints due to overloading of Vineyard 330/132 kV transformer under N-1 contingency.	Load driven

Ongoing projects

Powering Sydney's Future

The Powering Sydney's Future project will ensure the reliability of supply to businesses and residents in surrounding Sydney's Central Business District and surrounding areas. The project is a new 20 km, 330 kV cable between the existing Rookwood Road and Beaconsfield Substations with a capacity of ~750 MVA. To cater for future electricity demand growth, conduits for a second supply cable will be laid at the same time. Construction has started in August 2020 the new cable is expected to in service by June 2022.

To keep customer representatives informed during project execution, a Stakeholder Management Committee (SMC) was formed to work with TransGrid through the delivery of the project. The SMC members are a subgroup of the TransGrid Advisory Council (TAC).

Fast Frequency Response

Grid-scale batteries are a relatively new technology for the industry, providing services to the transmission network, the wholesale electricity market, and frequency control ancillary service markets. A grid-scale battery co-located with a transmission substation can also provide cost savings through its connection to existing assets (BNEF 2019)[29].

A network-owned battery can reduce the cost to consumers by stacking multiple benefits. TransGrid does not participate in energy or FCAS markets, but can make capacity available to market participants where there are complementary use cases for a BESS, to allow various types of benefits to be realised.

As part of the RIT-T for Powering Sydney's Future, a 10 MW battery at Beaconsfield was investigated as one element of the demand management solution. Space constraints and available connection capacity limited the battery size and interest from market participants, which led to the consideration of alternative locations for providing Fast Frequency Response (FFR) services.

TransGrid is installing a 50 MW/75 MWh battery in Western Sydney in late 2021 to pilot the provision of fast frequency response and synthetic inertia as network services, which would enable TransGrid to understand its battery technology performance during disturbances over a wide range of system conditions and validate its characteristic in system stability models. These network services are becoming increasingly important as more renewable generation joins the grid. The project has received funding from ARENA as part of ARENA's Advancing Renewables Program and the NSW Government as part of the Emerging Energy Program.

The installation of a pilot for fast frequency response is consistent with the AEMC's recommendations in its System Security Frameworks Review Final Report. The report recommends an obligation on TNSPs to provide minimum levels of inertia, or alternative equivalent services, to allow the power system to be maintained in a secure operating state.

If a grid connected storage solution is shared with other value streams, the cost allocation methodology will be applied to allocate the costs, as required under the Rules.

Completed projects

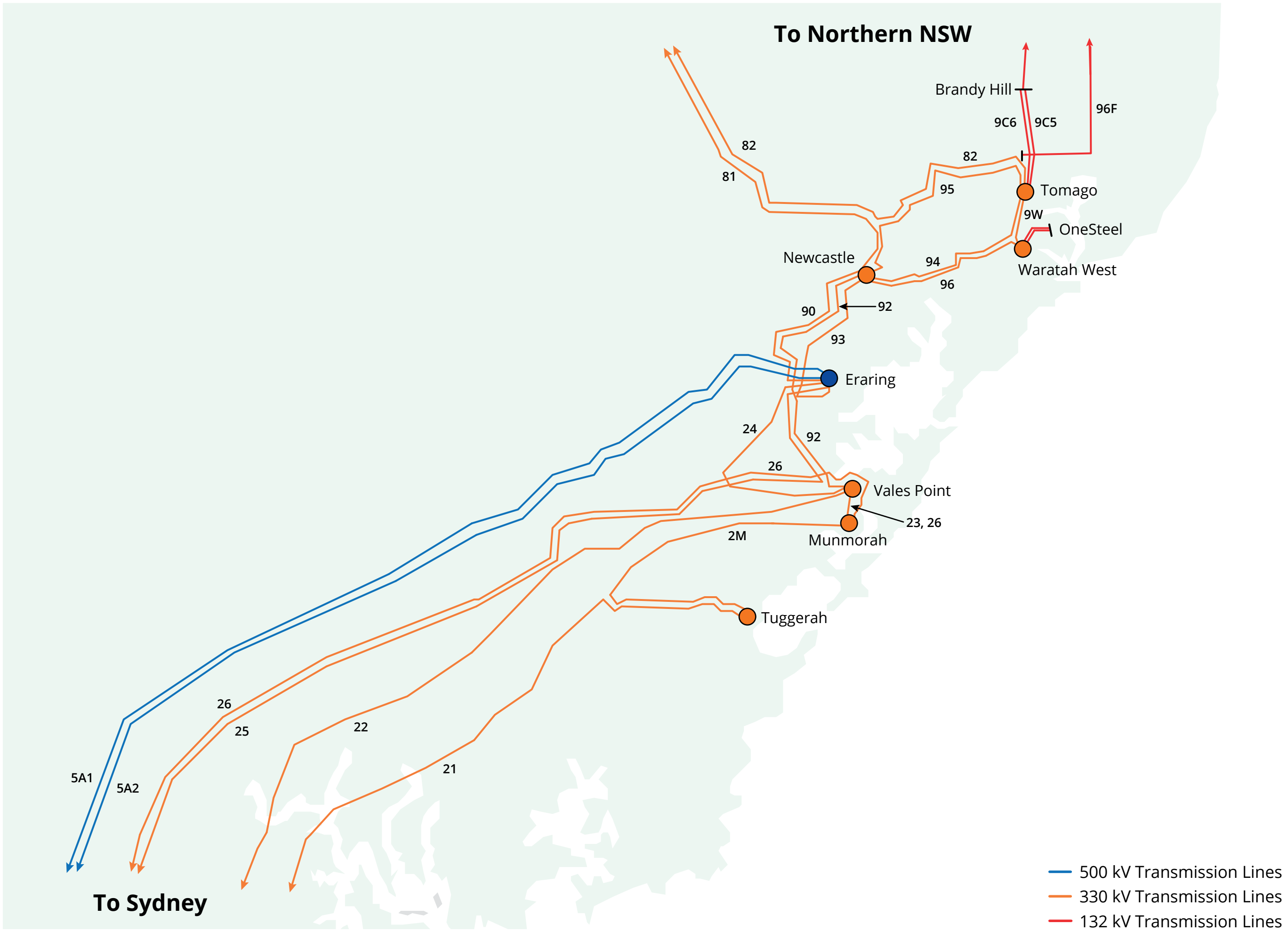
The following are projects which were completed after the 2020 TAPR was published:

- Installation of one 66 kV switchbay at Macarthur 330/132/66 kV Substation to connect Endeavour Energy's Menangle Park Zone Substation
- Cable 41 Voltage control scheme to manage overvoltage during low demand period
- Sydney West Dynamic Voltage Support project

29 BloombergNEF, Business Models for Energy Storage – Australian Examples, 1 August 2019.

2.3.2 Newcastle and Central Coast

Figure 2.13: Newcastle and Central Coast network



Planned projects

There are no planned prescribed augmentation projects in the Newcastle and Central Coast region.

Ongoing projects

There are no ongoing prescribed augmentation projects in the Newcastle and Central Coast region.

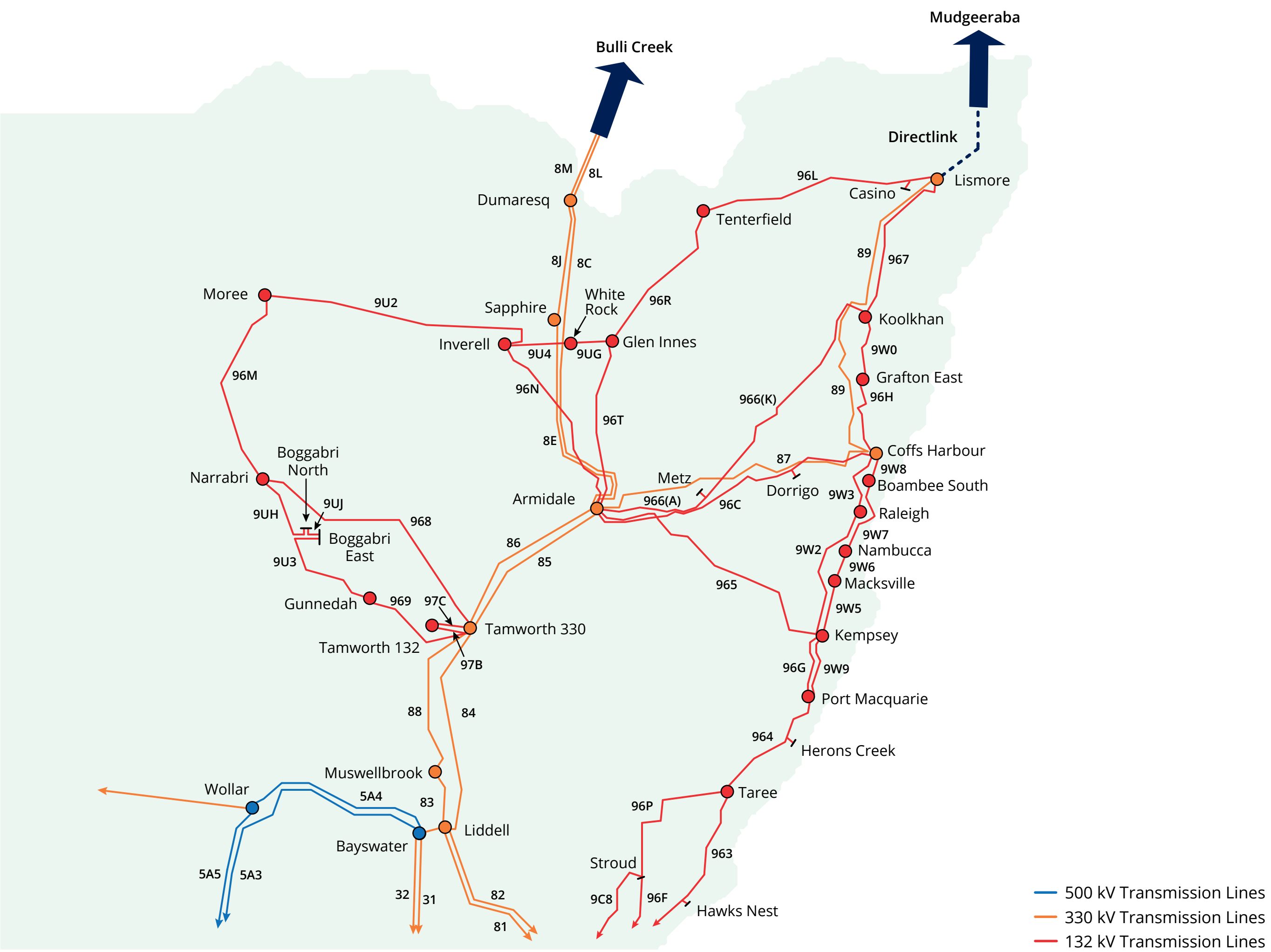
Completed projects

The following project was completed after the 2020 TAPR was published:

- Newcastle Data Centre Capability Upgrade project to deploy a new Energy Management System (EMS) and upgrade of the existing switch room in supporting the proposed new SCADA system during cutover, and upgrade of the associated data centre site at TransGrid's Newcastle Data Centre.

2.3.3 Northern NSW

Figure 2.14: Northern NSW network



Planned projects

The following projects are currently planned in the Northern region.

- Thermal and voltage constraints may arise in the Gunnedah area leading to an emerging risk to reliability if large mining or gas developments proceed in the area. These developments, along with other planned projects which improve security of supply to customers and provide economic benefits, are shown in **Table 2.2**.

Table 2.2: Planned projects in Northern NSW

Project description	Planned date	Total cost ($million April-21)	Purpose	Project justification
Armidale capacitor transfer tripping scheme	2021	0.3	Implementation of a transfer tripping scheme for the Armidale 132 kV capacitor bank to improve QNI transfer capability during an outage of an Armidale 330/132 kV transformer.	Improve transfer capability
Transposition of 330 kV lines 87 (Coffs Harbour to Armidale) and 8C/8E/8J (Armidale to Dumaresq)	2022	1.4	These transpositions are to manage negative-sequence voltage levels greater than 0.5% within the northern NSW transmission network.	Compliance
Maintaining reliable supply to the North West Slopes area	2025	210	Strengthen the Narrabri area to manage emerging voltage and thermal limitations due to load growth.	Load driven
Manage multiple contingencies in North West NSW	2025	3.6	Installation of a remedial action scheme to protect against trips of two or more of the 330 kV lines between Armidale and Liddell. For multiple circuit trips, the scheme will run back generation and load to avoid cascading outages and further loss of load in the network.	Economic benefits
Taree 132 kV bus capacity augmentation	2025	3	A trip of any 132 kV busbar section at Taree 132/66 kV Substation will interrupt supply to the Taree area. Installation of a new circuit breaker bay to allow two busbar protection zones at Taree Substation will allow continued supply to customers in the Taree area during a bus section outage.	Compliance
Voltage Control under light load conditions	2026	5.4	To address the high voltage issues during low demand period in Essential distribution network. The installation location will be optimised within the Moree / Inverell Region.	Voltage Control

Projects under Regulatory Consultation

TransGrid is currently undertaking a RIT-T to maintain reliable supply to the North West Slopes area.

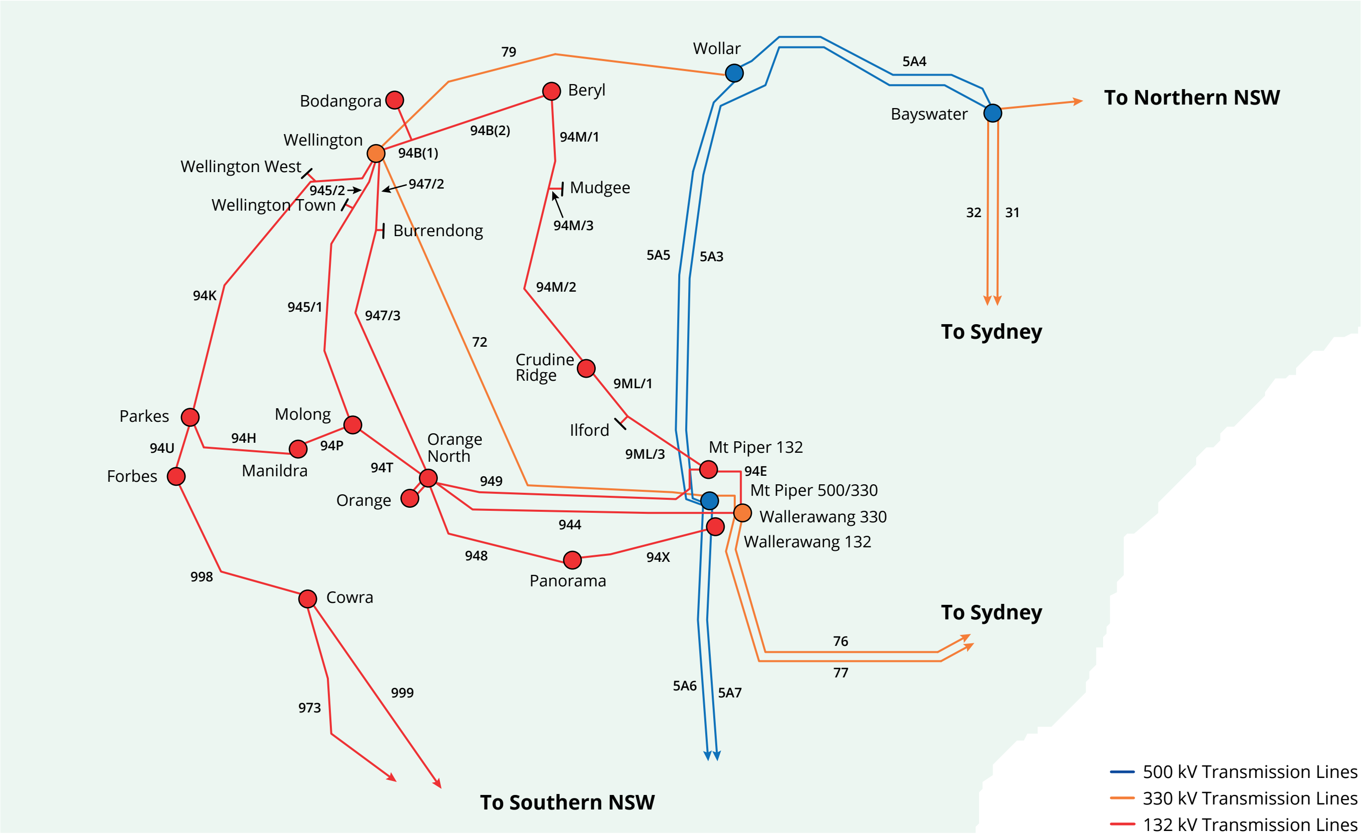
Completed projects

The following project was completed after the 2020 TAPR was published:

- The Armidale number 2 reactor was replaced to address its end-of-life condition.

2.3.4 Central NSW

Figure 2.15: Central NSW network



Planned projects

The following are planned projects in the Central NSW region:

- The central NSW network has limited available capacity and this imposes constraints on connection of large loads or generation in the area. This is mainly due to voltage and thermal limitations. Outages of elements in the network pose significant risks to the network due to the limited capability to supply the load and connect generation, mostly in the 132 kV network.
- The Orange and Parkes areas are forecast to experience significant demand growth over the next 10 years mainly due to industrial load demand. The network will need to be reinforced in order to alleviate emerging network constraints associated with the demand growth and to improve the reliability of supply in the area.
- There is strong interest from renewable energy proponents seeking to connect to the 330 kV transmission network between Wollar and Wellington. TransGrid is currently investigating potential transmission augmentation within the Central West to support the development of the Central-West Orana REZ (Refer to **Section 2.1.7**).
- Planned projects in the area which improve the reliability of supply to customers and provide economic benefits are shown in **Table 2.3**.

Table 2.3: Planned projects in Central NSW

Project description	Planned date	Total cost ($million April-21)	Purpose	Project justification
Supply to Parkes area (short-term)	2022	5 to 14	The network around Parkes area will need to be reinforced to reliably supply the increased demand in the short-term. A range of network and non- network options are being considered to manage the associated network constraints. This include the installation of one or more capacitor banks at optimal locations in the Parkes area. Further network augmentation will be required in this area to manage the load growth in the long-term (as explained under planned project "Maintaining reliable supply to Bathurst, Orange and Parkes areas").	Compliance
Maintain voltage in Beryl area	2023	23	We have identified potential voltage constraints and reactive margin shortfall issues in the Beryl area. TransGrid has identified a range of credible network and non-network options to address these network constraints. The options include building a synchronous condenser, establishment of Beryl 330/132 kV Substation cut-in to existing line 79 and other network development options.	Compliance
Increase capacity for generation in Molong to Parkes area	2024	7	With number of renewable generators being in-service and committed to connect in the network West of Molong Substation, the output of these renewable generators will have to be curtailed due to the relatively low thermal rating of the line 94T. TransGrid has identified a range of credible network and non-network options to address this constraint. The options include rebuilding the line, implementing dynamic line rating and other network development options.	Economic benefits
Maintaining reliable supply to Bathurst, Orange and Parkes areas	2024	550 to 750	It is expected that the demand in Orange and Parkes areas will increase significantly over the next 10 years mainly due to the industrial demand growth in the area. Further growth is expected around Parkes with the NSW Government's Parkes Special Activation Precinct. To manage the longer-term demand and the associated network constraints in the area, various network and non-network options have been identified. The identified network options include establishment of a new 330/132 kV substation by cut-in to Line 72 and linking with existing substations and other network development options.	Compliance
Increase capacity for generation to Beryl area	Subject to new generation being committed in the Wellington to Mt Piper area	TBD	With more renewable generation being integrated in to the network around Beryl, the outputs of these generators will have to be constrained due to the thermal capacity limitation of the 132 kV network between Wellington to Mount Piper. A range of credible network and non-network options are being considered to address this network constraint.	Economic benefits
Increase capacity for generation in Wollar to Wellington area	Subject to the level of renewable generation committed to connect to Line 79 and the development of Central-west Orana REZ	50-100	There is a strong interest from the renewable proponents to connect to the network between Wollar to Wellington. Six renewable generators with a total capacity of about 2100 MW have applied to connect to the transmission network in this area. The network studies have identified that this could lead to a number of network constraints including voltage and thermal constraints. TransGrid has identified a range of credible network and non-network options to address these network constraints. The options include rebuilding or duplicating line 79 and a number of other network development options.	Economic Benefits

Projects under Regulatory Consultation

TransGrid is currently undertaking a RIT-T to maintain reliable supply to Bathurst, Orange and Parkes areas.

Ongoing projects

There is an ongoing prescribed augmentation project to Install two new capacitor banks (10 MVAr each) at Panorama Substation (132 kV) and Orange North Substation (132 kV) to provide voltage support to the area.

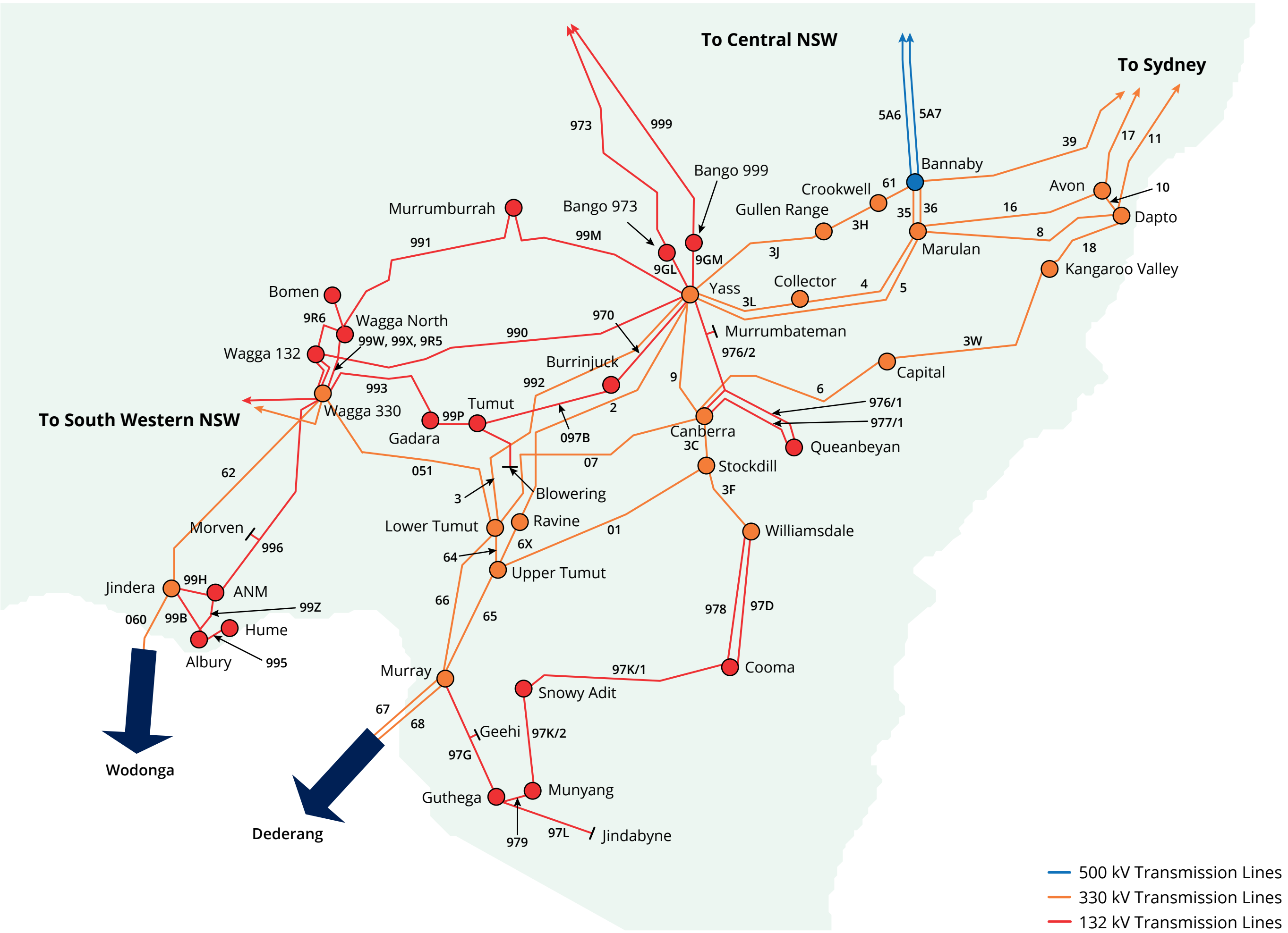
Completed projects

The following project was completed after the 2020 TAPR was published:

- Installation of a back-up Under Voltage Load Shedding scheme (UVLS) at Parkes 132 kV Substation

2.3.5 Southern NSW and ACT

Figure 2.16: Southern NSW and ACT network



Planned projects

The following are planned projects in the Southern NSW and ACT region:

- The transmission network augmentations required to maintain the supply reliability and facilitate the potential developments in ACT have been planned. A project has been raised to improve the supply reliability and resilience to the ACT network to avoid unplanned loss of load during planned and forced outages. Option feasibility studies are underway where credible options include installation of a new 330/132 kV transformer at Canberra 330/132 kV substation.
- A number of Joint Planning projects are progressing in collaboration with Essential Energy for the Southern area as listed below.
  - TransGrid is planning to provide an 11 kV bulk supply point at Upper Tumut 330 kV switching station in order to restore the supply to Cabramurra and Mt Selwyn area. The project had been raised followed by the severe bushfire damage to the Essential Energy's sub transmission lines supplying Cabramurra and Mt Selwyn area.
  - In order to provide 132 kV and 11 kV voltage regulation at Murray and hence reduce the negative impact on the 132 kV subsystem and distribution network (Khancoban town) due to variations in 330 kV voltage, TransGrid is investigating installing on-load tap changer facility at Murray 330/132 kV transformers which are to be replaced due to their asset condition. Further, in order to minimise the risk posed by the unearthed 11 kV reticulation in Khancoban town during outages of TransGrid's Murray Substation 330/132/11 kV transformers, TransGrid and Essential Energy are jointly investigating possible solutions to reduce the negative impact on the quality of power.
- There are a number of renewable generators and energy storage systems proposed to connect to the TransGrid's Southern subsystem especially in Wagga area. Projects have been raised to remove the potential thermal constraints in the sub system between Wagga and Yass especially to unlock the renewable generation in the North of Wagga North and increase the transfer capacity between Wagga and Yass.
- Other planned projects in the area includes those in **Table 2.4**.

Table 2.4: Planned projects in Southern NSW and ACT

Project description	Planned date	Total cost ($million April-21)	Purpose	Project justification
Diversion of ACT Emergency bypass arrangement at Yass	2021	1.62	To relocate the existing bypass arrangement at Yass, in order to facilitate the installation of the SmartValve on Line 2 swicthbay. The bypass is required to meet the requirements of the ACT Electricity Transmission Supply Code 4.1.1(1)(d) to supply the ACT agreed maximum demand within 48 hours of a special contingency event.	Compliance and Regulatory Obligation
Dynamic ratings for Yass 330/132 kV transformers	2022	1.8	With the developments in renewable generation in the subsystem in Wagga and Yass areas there will be a significant reverse power flow in Yass 330/132 kV transformers during high demands times. This project implements a real time monitoring system and the required upgrades to facilitate a dynamic rating system for the 330/132 kV transformers at Yass 330 kV substation.	Economic benefits
Install Static Synchronous Series Compensation on 2 Upper Tumut – Yass 330 kV Line	2022	TBC	To improve the sharing between the four 330 kV lines 01, 2, 3 and 07 and thereby enable higher transfer across the group. A 2Ω reduction in the line reactance will increase the Snowy to NSW transfer capability by 26 MW.	Economic benefits
Yass-Wagga Line Over Load Scheme (LOLS) expansion	2022	TBC	To manage of the post-contingent overloads of the 132 kV network in the interconnection between Yass and Wagga hence avoid the requirement for pre-contingent generator constraints being implemented. The project expands the existing Yass and Wagga LOLS into a unified scheme to monitor all 132 kV lines between Yass and Wagga.	Economic Benefits
Installing Quality of Supply (QoS) meters at Munyang	2022	0.2	Due to the nature of the load characteristics, there is a potential for voltage distortion levels at Munyang to exceed the respective limits. This project installs QoS meters on the 33 kV side of No.1 and 2 transformers at Munyang to monitor the voltage distortion to be able to ensure that supply standards are met.	Compliance
Reactive Support at Wagga 330 kV Substation	2022	4.8	Possible voltage collapse in southern NSW for loss of the largest VIC generating unit or Basslink limits the NSW – VIC transfer limit. A 100 MVAr capacitor at Wagga will lift the southward transfer limit by 30 MW and northward transfer limit by 75 MW.	Economic benefits
Install Static Synchronous Series Compensation on 62 Jindera – Wagga 330 kV Line	2023	TBC	To improve the sharing between the three 330 kV lines 62, 65 and 66 and thereby enable higher power transfer across the group. This facility will achieve a 12.8 MW increase on the NSW-VIC thermal constraint and a 5.6 MW increase on the NSW-VIC voltage constraint.	Economic benefits
Busbar capacity upgrade at Wagga 132 and Yanco	2023	12.8	To increase the ratings of the 132 kV and 66 kV busbar sections at Wagga 132 substation and 132 kV busbar sections at Yanco substation hence remove the thermal constraints at those sites during high renewable generation times and/or outages conditions.	Economic Benefits/Load driven
Improve fault ratings in Southern NSW	2025	51.8	The fault levels in the Southern transmission network will increase due to a number of major projects planned in the southern network. This project upgrades substation switchgear and earth grid to meet the increased fault levels.	Compliance

Project description	Planned date	Total cost ($million April-21)	Purpose	Project justification
Increased capacity between Wagga North and Wagga	2025	10.7	This project addresses the potential thermal overloading in the 132 kV Lines 9R5 and 9R6 due to renewable generation developments in Wagga North area and the proposed NSW Government's Wagga Wagga Special Activation Precinct. A range of options have been considered to reconducting the Lines 9R6 and 9R5 or building a new transmission line.	Economic benefits
Improving the power quality issues in ACT	2026	8.4	To minimise the temporary over or under voltage conditions that could occur during switching of existing capacitors at Canberra in distribution network. Options being considered include: • Reconfiguring the 120 MVAr 132 kV capacitors as 80 MVAr and add a 120 MVAr 330 kV capacitor • Modifying Evoenergy's existing scheme to pre-emptively vary 11 kV voltages	Compliance
Strategic corridor acquisition for South Western NSW	2026	30	To secure outlet routes from Wagga 500 kV substation for future network development and for a distance from the substation sufficient to prevent the sterilisation of connection access to the substation, but not too far so as to limit route options for the feeder as a whole.	Strategic Property
Establishment of a new 132 kV switchbay at Canberra 330/132 kV Substation	2027	3	To facilitate the supply to the Evoenergy's proposed Strathnairn Zone Substation to be able to meet the projected load growth due to the new residential development in Canberra.	Load driven

Ongoing projects

Connection to Molonglo substation: Construction of two 132 kV line switch bays at recently built Stockdill 330 kV substation is underway. This project facilitates the 132 kV connection to Evoenergy's proposed Woden tee Molonglo feeder (9HC) and Canberra feeder (9HF) to be supplied via TransGrid Stockdill 330 kV substation.

Thermal capacity upgrading of the 132 kV Line 99X (Wagga 330 – Wagga 132) by replacing the limiting equipment at Wagga 330 and Wagga 132 is progressing and planned to complete in November 2021. This project will improve the supply reliability at Murrumburrah during high import times to NSW from Snowy/VIC. Uprating the Line 99X will also provide market benefits during high renewable generation in Wagga area.

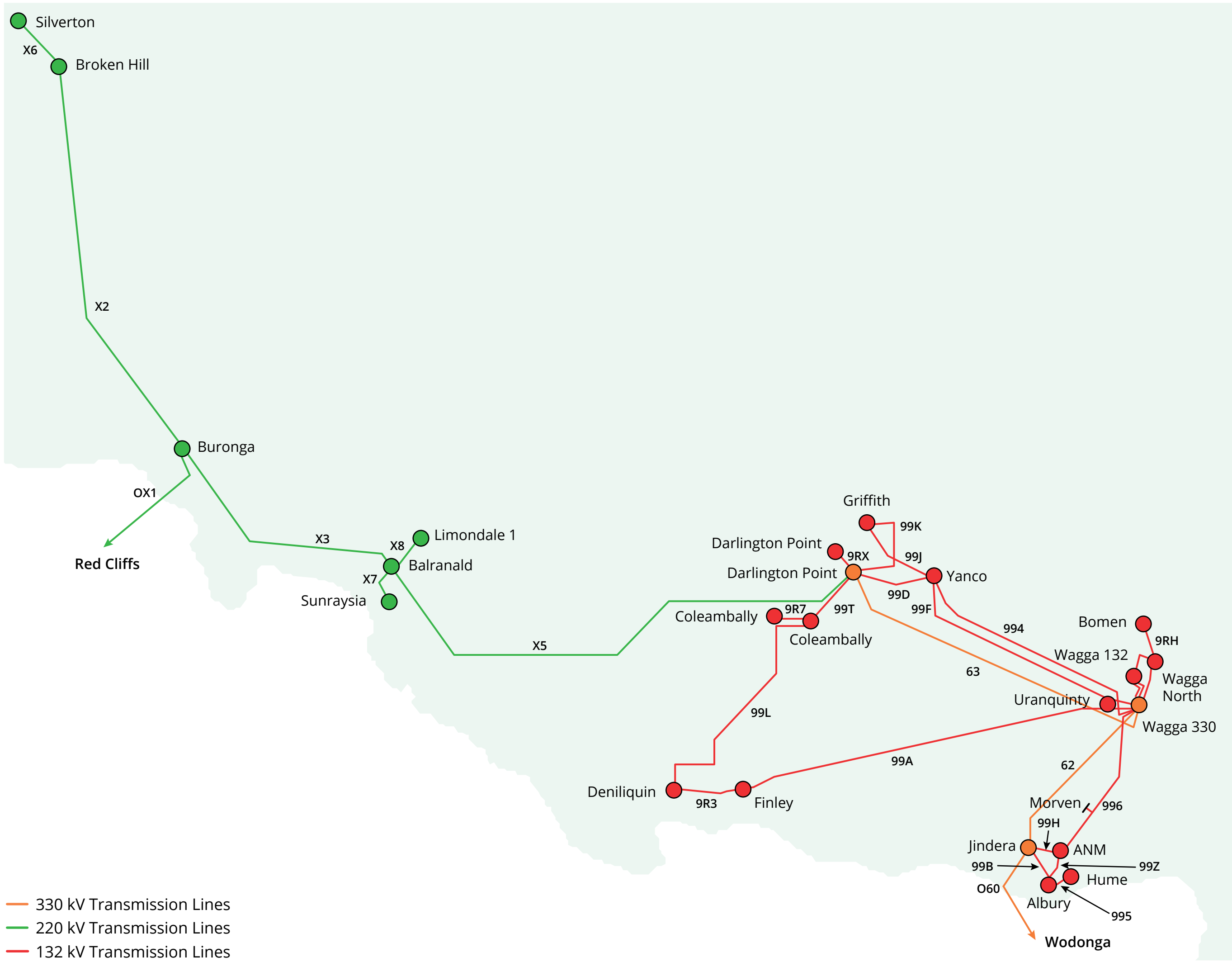
Completed projects

The following are projects that were completed after the 2020 TAPR was published:

- Establishment of the Stockdill 330 kV substation, the second geographically independent bulk supply point to the ACT has been completed in 2020. The project comprises 5.6 km of transmission line, 20 towers, a 132 kV emergency bypass and the decommissioning of two 330/132 kV transformers and associated switchgear at Canberra Substation.
- Increased the Summer Day contingency rating of the 132 kV Line 993 (Wagga 330 - Gadara) from 114 MVA to 137 MVA by remediating the low spans associated with the line which includes 90 structure replacements and landscaping of 2 spans to gain required conductor electrical clearance.
- Marulan No. 3 330/132/33 kV transformer (160 MVA) was replaced with a 200 MVA 330/132/11 kV transformer to address the end of asset condition while increasing the transfer capacity.

2.3.6 South Western NSW

Figure 2.17: South Western NSW network



Planned projects

The following are planned projects in the South Western region:

- There will be major network augmentations across South-Western NSW from Buronga to Wagga as part of the SA/NSW interconnector project which strengthens the existing transmission network. This includes construction of a 330 kV double circuit transmission line from Buronga to Wagga, an intermediate switching station located in south of Darlington Point (Dinawan) and installation of dynamic and static reactive plants at Buronga, Dinawan and Wagga.
- Projects have been initiated to manage the risk of over voltages in South-western NSW that could occur due to minimum demand conditions especially when reactive power support is not available from the renewable generators. As part of these projects a remedial action scheme will be implemented to reduce the over voltages in Darlington Point area during critical contingencies by the 330 kV Line 63 (Wagga –Darlington Point) at both ends. Another project is investigating the possible network and non-network solutions to manage the excessive voltages in the 132 kV link between Darlington Point, Coleambally, Deniliquin and Finley during critical contingencies when demand levels are low.
- TransGrid is currently investigating the feasibility of potential transmission augmentation within the South West to support the development of a Southern REZ (Refer to **Section 2.1.5**).
- Other projects planned in the area includes those in **Table 2.5**.

Table 2.5: Planned projects in South Western NSW

Project description	Planned date	Total cost ($million April-21)	Purpose	Project justification
Broken Hill 220 kV busbar fault rating upgrade	2021	0.35	A staged process has been identified to assess and ensure that fault rating capability of the 220 kV busbar equipment is adequate for the increased and expected further increase in fault level due to renewable generation and major network augmentations. This scope includes testing the actual fault rating capability of an existing 220 kV HV equipment to confirm the equipment capability.	Compliance
Maintain supply reliability to Broken Hill	Unavailability of existing diesel-fired turbines (January 2022, or earlier)	52 to 350	To provide back-up supply when Line X2 is out-of-service, and the expected unserved energy exceeds the IPART reliability standard for Broken Hill (10 minutes at average demand). Possible options include: energy storage solutions to replace or complement the existing gas-turbines, additional gas turbine generation with a short start-up time, procuring demand management from the loads in the area, and constructing a second 220 kV line from Buronga to Broken Hill.	Reliability
Darlington Point 330/220/33 kV Tie Transformer cross tripping scheme.	2022	TBC	At times of high renewable generation in far west NSW, there will be very high flows towards Darlington Point. Currently the dispatch from renewable generation in far west is constrained pre-contingent to prevent overloading of 200 MVA 330/220/33 kV transformers during a trip of the other transformer. This project implements a remedial action scheme to trip the remaining tie transformer hence allow the tie transformers run at their maximum MVA rating.	Economic benefits
Broken Hill 22 kV busbar fault rating upgrade	2023	7.4	Due to the network developments in far West NSW, the fault level at Broken Hill will increase beyond the fault rating of some primary equipment. This project investigates the non asset and asset based investments to address the increased fault levels at 22 kV side at Broken Hill.	Compliance
Uprating the Darlington Point 330/132 kV Transformers	2023	4	The rating of the Darlington Point 330/132 kV transformers is limited to 280 MVA due to the size of the cooler banks. Under this project, the cooler banks will be upgraded to increase the transformer rating to its nameplate rating of 375 MVA.	Economic benefits
Install dynamic transformer rating equipment on Darlington Point 330/220/33 kV Tie Transformers	2023	1	To optimise the operating capability of the tie transformers by using their real time ratings to reduce the constraints on the future SA/ NSW interconnector and renewable generation.	Economic benefits
Improve stability in South-Western NSW	2024	TBC	To alleviate the stability issues during outage of 330 kV Line 63 (Wagga 330 to Darlington Point) which are presently managed by power flow constraints and transfer trip schemes. Options considered include building a new 330 kV Line between Darlington Point and Dinawan and installation of STATCOM.	Economic Benefits
Improve voltage control in Southern NSW area	2024	7.7	The reduction in minimum demand in Southern New South Wales is causing high voltage issues in the southern network. To address the high voltage issues during low demand period in TransGrid's Southern Network. The installation location will be optimised within the southern region.	Voltage Control
Strengthening far west NSW	2024	15.2	This project will improve the network capability in far western 220 kV network to facilitate load growth in the Broken Hill area. Potential voltage constraints will be removed by providing reactive support at Broken Hill hence improving the voltage stability limit.	Load Driven

Ongoing projects

Ongoing projects in the South Western region:

- Installation of disturbance recorder and phase measurement units (PMU) at Broken Hill, Buronga and Darlington Point is progressing. This project addresses the need to monitor the oscillations that could arise due to operation of multiple solar farms in the far Southwest NSW and North West Victoria which could lead to post-contingent oscillatory instability impacting the power system in the north west Victoria and south west New South Wales. Disturbance Recorders and PMUs at Darlington Point, Buronga and Broken Hill substations and to stream the data in real time to AEMO for the use validate system modelling. The expected project completion is December 2021.
- There are ongoing secondary systems upgrade projects at a number of substations including Coleambally, Deniliquin, Darlington Point, Balranald Broken Hill and Buronga Substations. Refer **Section 2.4.3** for more details.

Completed projects

Completed projects in the South Western region after the TAPR 2020 was published:

- The Line 99D (Griffith – Darlington Point) refurbishment project was completed replacing a number of wood poles identified as having condition issues to extend the life of the lines for a period of 10 years.
- Broken Hill earth fault protection system upgrade: The old electromechanical relays were replaced with modifications to the protection panels to address the safely and reliability risk.
- Installing OPWG communication in Line 99T has been completed along with the refurbishment project of 99T replacing the previously used PDH link. Improved communication reliability is expected in operation of the network in this area.

2.3.7 Across NSW

NSCAS needs

NSCAS are ancillary services procured in order to maintain power system security. Under the NER, AEMO identifies NSCAS needs and TransGrid is required to procure the services to address the needs in NSW. AEMO is the NSCAS Procurer of Last Resort if a TNSP is not able to procure the NSCAS to meet their requirements. The 2018 NTNDP published in June 2018 by AEMO did not identify any NSCAS gaps in NSW.

System strength and inertia requirements

With the retirement of coal fired power stations in the next 10 years, there is a risk of NSW not meeting the planning requirements for system strength and inertia. It is likely that additional measures will be required by the retirement of Eraring Power Station following the Liddell and Vales Point Power Station closures. These measures could include synchronous condensers with flywheels, conversion of retiring generators to synchronous condensers, contracting non-base load synchronous machines (generators), 'synthetic inertia' from wind generators and Fast Frequency Response from Battery Energy Storage Systems (BESS) and power electronic based generators.

Table 2.6 and **Table 2.7** give an indicative list of projects in the next 10 years to meet system strength and inertia requirements. These include shortfalls expected after Eraring retirement in 2032. The shortfalls can occur earlier than expected if coal-fired power stations retire early or move to flexible operation where they can go offline during times of light load or low price. Due to lead time in implementing, TransGrid will need to identify and commence these projects in the next 10 years.

Table 2.6: Indicative projects to meet system strength requirements (refer Table 5.3)

Location or Region	Indicative system strength remediation to meet shortfall
Armidale	Synchronous condensers or equivalent services that provide up to 360 MVA by 2036 at Armidale 330 kV
Darlington Point	No remediation is required in the next 10 years as per AEMO minimum requirements
Newcastle	Synchronous condensers or equivalent services that provide up to 1850 MVA by 2032 and 4280 MVA by 2036 at Newcastle 330 kV
Sydney West	Synchronous condensers or equivalent services that provide up to 1320 MVA by 2032 and 4060 MVA by 2036 at Sydney West 330 kV
Wellington	Synchronous condensers or equivalent services that provide up to 260 MVA by 2036 at Wellington 330 kV

Table 2 7: Indicative measures in the next 10 years to meet inertia requirements (refer Table 5.5)

Location or Region	Indicative inertia remediation to meet double generator contingency inertia level of 15,000 MWs (MWs)
NSW	8,300 MWs in NSW by 2032 (which at least 3,300 MWs needs to be synchronous inertia)

Planned projects

Table 2.8: Planned projects across NSW

Project description	Planned date	Total cost ($million April-21)	Purpose	Project justification
Transformer automatic voltage regulator (AVR) function changes	2023	0.1	To fulfil the obligation under the National Electricity Rules (NER) to ensure voltage levels at customer connections points are controlled to an agreed supply point voltage. Modification of AVR logic to allow automatic voltage regulation during reverse power flow at locations with high levels of embedded renewable generation.	Economic benefits
Provide Dynamic Line Rating on various lines	2023	3.7	Weather stations will be installed to allow Dynamic Line Ratings to be calculated for a number of lines. Replacement of limiting equipment will permit use of higher ratings. Operating these lines to a dynamic rating appropriate to ambient conditions will facilitate construction and dispatch of additional low-cost generation.	Economic benefits
Improve performance of Remedial Action Schemes	2024	9	Upgrade under-performing Remedial Action Schemes	Economic benefits
Overvoltage control following under frequency load shedding events	2025	9.3	Implementation of overvoltage control schemes to automatically switch existing reactive plant quickly to maintain system security when the system frequency falls below a certain level.	Economic benefits
Remote or self-reset of busbar protection	2028	6.8	Installation of high definition Closed Circuit Television (CCTV) on busbars and facilities to reset busbar protections remotely at selected sites. This will reduce restoration time and duration of supply interruptions following busbar faults.	Economic benefits

Ongoing projects

Routine customer requests for changes to secondary equipment such as protection or voltage regulation are ongoing.

Completed projects

No prescribed augmentation state-wide projects were completed in the 2020/21 financial year.

2.4 Replacement projects

The retirement of assets is planned as they reach the end of their serviceable life. We continue to improve the asset management strategies and policies which underpin the capital investment process. The risk of asset failure is continually monitored, as well as its impact on reliability, safety and on communities through bushfire and other environmental damage. A risk profile for each major asset is used to identify when action needs to be taken for high risk assets.

Options to mitigate the risk are evaluated, including:

- Do nothing or increase maintenance interventions;
- Defer the need for replacement, if viable non-network options are available;
- Like-for-like replacement;
- Replacement with an asset of different capacity based on forecast demand; or
- Reconfigure the network.

By using economic analysis and consideration of TransGrid regulatory safety obligations to determine the appropriate course of action, TransGrid endeavours to invest and operate the network prudently in alignment with the National Electricity Objective (NEO) "...to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to – price, quality, safety, reliability, and security of supply of electricity; and the reliability, safety and security of the national electricity system..."

The projects described have used this approach to determine the best solution for the identified needs. This section will describe TransGrid's capital replacement works grouped by asset classes or work programs. The information provided in this section describes the work, the actual or potential constraint or inability to meet network performance requirements of the NER Schedule 5.1, the need date, proposed solution and its estimate. Given that they are mostly in-situ or like-for-like replacement projects, they do not cause any material inter-network impact.

The information reported in this section meets the requirement of the NER Clause 5.12.2(c)(5) and (6).

TransGrid presently does not anticipate any replacement project required to address an urgent and unforeseen network issue.

2.4.1 Transmission lines

Steel tower corrosion management

A refurbishment program that addresses steel tower corrosion issues is being undertaken on coastal tower transmission lines in the Newcastle, Central Coast, Sydney and Illawarra regions. The program includes refurbishment of rusted steel towers and the replacement of conductor fittings, earth wires and insulators at risk of failure.

These identified condition issues increase the probability of failure of a steel tower, conductor fittings, earth wires and insulators. Analysis has shown that risk costs can be offset by extending the lives of transmission lines through targeted refurbishment and replacement of specific components. The following table provides a list of transmission lines with steel towers requires corrosion management:

Table 2 9: Planned steel tower transmission line asset renewal projects

Transmission line location	Operational date required	Total estimated cost ($ million)
22 Vales Point – Sydney North 330 kV line	Dec 2021	11.4
3W Capital Windfarm – Kangaroo Valley 330 kV line	Aug 2021	7.4
27 Sydney North – Sydney East 330 kV line	Feb 2022	3.2
17 Macarthur – Avon 330 kV line	Dec 2021	7.4
8 Dapto – Marulan 330 kV line	Apr 2022	9.0
28 Sydney North – Sydney East 330 kV line	Aug 2022	5.8
25 & 26 Eraring – Vineyard 330 kV line & Munmorah – Sydney West 330 kV line	Aug 2022	20.1
81 Liddell – Newcastle 330 kV line	Dec 2022	11.0
18 Dapto – Kangaroo Valley 330 kV line	Jan 2023	8.9
90 Eraring – Newcastle 330 kV line	Mar 2023	2.5
21 Sydney North – Tuggerah 330 kV line	Apr 2023	15.0
93 Eraring – Newcastle 330 kV line	Oct 2023	1.7
14 Kemps Creek – Sydney North 330 kV line	Jun 2023	5.8
24 Eraring – Vales Point 330 kV line	Jun 2023	2.8
16 Avon – Marulan 330 kV line	Jun 2028	8.9
11 Dapto – Sydney South 330 kV Line	Aug 2028	85.0
23 Values Point – Munmorah 330 kV line	Jun 2028	TBA
963/96P - Tomago - Taree - Stroud 132 kV line	Jun 2028	1.2
12/76 Sydney West – Sydney South - Wallerawang - 330 kV line	Jun 2028	5.6
13/78 Kemps Creek - Sydney South - Ingleburn 330 kV line	Jun 2028	4.5
76/78 Sydney South - Wallerawang - Ingleburn 330 kV line	Jun 2028	3.6
76/77 Sydney South - Wallerawang - Ingleburn 330 kV line	Jun 2028	TBA
25/92 - Eraring - Vales Point 330 kV line	Jun 2028	3.6
25/93 - Eraring - Vales Point 330 kV line	Jun 2028	2.0
82 - Liddell - Tomago 330 kV line	Jun 2028	9.0
82/95 - Tomago - Newcastle 330 kV line	Jun 2028	4.3
95 - Tomago - Newcastle 330 kV line	Jun 2028	2.2
8C/8E - Sapphire - Armidale 330 kV line	Jun 2028	18.8
8C/8J - Sapphire - Armidale 330 kV line	Jun 2028	8.3
8L/8M - Texas - Dumaresq 330 kV line	Jun 2028	6.5
24/90 - Eraring - 8C 330 kV line	Jun 2028	1.2
31-32 Bayswater-Regentville DC 330 kV line	Jun 2028	TBA
88 - Muswellbrook - Tamworth 330 kV line	Jun 2028	TBA
13 - Kemps Creek - Sydney South 330 kV line	Jun 2028	3.1
29/26 - Eraring - Vineyard - Sydney West 330 kV line	Jun 2028	4.5
92/93 - Vales Point - Eraring - Newcastle 330 kV line	Jun 2028	2.4
90/92 – Vales Point - Eraring - Newcastle 330 kV line	Jun 2028	1.4
94/96 - Newcastle - Tomago - Waratah 330 kV line	Jun 2028	3.4
9W/96 - Newcastle - Tomago - Waratah 330 kV line	Jun 2028	1.4
12 - Liverpool - Sydney South 330 kV line	Jun 2028	4.2
1 - Stockdill - Upper Tumut 330 kV line	Jun 2028	4.2
7 - Lower Tumut - Canberra 330 kV line	Jun 2028	TBA
2 - Yass - Ravine 330 kV line	Jun 2028	TBA
6X - Ravine - Upper Tumut 330 kV line	Jun 2028	TBA

Wood pole replacements

TransGrid is replacing wood pole structures in poor condition on some 132 kV transmission lines with concrete or steel poles to address deterioration from wood rot, decay and termite attack. The following table provides a list of transmission lines with wood poles that requires replacement:

Table 2.10: Wood pole replacement projects

Transmission line location	Operational date required	Total estimated cost ($ million)
86 - Tamworth - Armidale 330 kV line	Jun 2028	140 to 200
977/1 - Canberra - Queanbeyan 132 kV line	Jun 2028	8.7
966 - Armidale - Koolkhan 132 kV line	Jun 2028	13.1
964 - Taree - Port Macquarie 132 kV line	Jun 2028	2.7
965 - Armidale - Kempsey 132 kV line	Jun 2028	TBA
978 - Williamsdale - Cooma 132 kV line	Jun 2028	TBA
963 – Tomago – Taree 132 kV Line	Jun 2028	7.7
968 - Tamworth - Narrabri 132 kV line	Jun 2028	TBA
94M - Beryl - Crudine Ridge windfarm 132 kV line	Jun 2028	6.8
9ML - Mount Piper - Crudine Ridge windfarm 132 kV line	Jun 2028	5.2
991 - Murrumburrah - Wagga North 132 kV line	Jun 2028	TBA
992 - Burrinjuck - Tumut 132 kV line	Jun 2028	TBA
947 - Wellington - Orange North -132 kV line	Jun 2028	TBA
99B - Jindera - Albury 132 kV line	Jun 2028	3.3

Transmission line location	Operational date required	Total estimated cost ($ million)
99Z - ANM - Albury 132 kV line	Jun 2028	2.8
94U - Parkes - Forbes 132 kV line	Jun 2028	18.6

Remediation of low spans

Transmission lines are designed and constructed to achieve standard electrical clearances of the conductor at specific operating conditions. The currently accepted industry standard is AS7000 for the Design of Overhead Lines, which specifies minimum electrical clearances that should be achieved when the conductor reaches its maximum operating temperature (also commonly referred to as the line design temperature).

TransGrid conducted aerial laser surveys of transmission lines to provide accurate measurement of span heights. Using this new technology which provides more accurate measurements than previous approaches, a number of transmission lines have been found to have spans violating AS7000 minimum clearances (low spans) at the normal foreseeable operating temperature. These low spans pose a risk to public safety. TransGrid also conducted a risk assessment on the identified low spans. The risk assessment method evaluates each low span violation in accordance with multiple risk criteria including magnitude (height and area), location and violation temperature.

The spans have been ranked accordingly and categorised as presenting a higher risk and lower risk to public safety. The remediation options considered include:

- Remediate all low spans; and
- Remediate higher risk low spans only, with the lower risk spans addressed by means of administrative control measures.

The remediation of higher risk low spans is proposed to reduce the level of risk to public safety across the network. TransGrid is required to fulfil the requirements of AS5577 Electricity Network Safety Management Systems, and the public safety risk presented by the low spans must be reduced As Low As Reasonably Practical (ALARP). The proposed remediation works aim to mitigate the public safety risk to an acceptable level. The following table provides a list of transmission lines with low spans:

Table 2.11: Low Span Projects

Transmission line location	Operational date required	Total estimated cost ($ million)
Low spans on various lines – Stage 2	Apr 2022	3.1
Low spans – Main grid on 330 kV lines	Jun 2028	TBA
Low spans – 132 kV lines	Jun 2028	TBA

Grillage Towers

TransGrid's earliest transmission towers (now 50 to 60 years old) have been installed with grillage foundations where the footings are constructed from hot-dip galvanised steel members formed into a grill and direct buried.

This type of foundation did not use any concrete, relying on the steel frame and the encapsulated soil as the foundation support for the tower superstructure.

Sacrificial anodes have been installed at various times on these towers to provide galvanic cathodic protection as a mitigation measure against footing corrosion.

A field assessment of the cathodic protection system and grillage condition on a sample of towers conducted in April 2016 has concluded that the installed sacrificial anodes are no longer providing sufficient protection against tower footing steelwork corrosion.

It is expected that these anodes have been consumed while providing sacrificial protection to the buried tower foundations and therefore have reached the end of their useful life.

Corrosion of buried steelwork is coupled to the soil exposure classification, as described in AS2159, which determines the rate at which buried steel is expected to corrode in various ground and environmental conditions. Remediation could include tower footing concrete encapsulation (after required steel remediation) or anode replacement. The following table provides a list of transmission lines that requires grillage tower remediation:

Table 2.12: Grillage Tower Remediation

Transmission line location	Operational date required	Total estimated cost ($ million)
Grillage refurbishment across NSW	Jun 2023	22.0

2.4.2 Substation plant

The condition of substation assets is continuously monitored to ensure safe and reliable operation. Asset replacement programs have been established to cover the replacement of identified circuit breakers, instrument transformers, bushings and disconnectors in poor condition.

The replacement programs comprise the most economic combination of replacement and refurbishment options for transmission equipment reaching a condition which reflects the end of its serviceable life. The asset replacement projects forming these programs are individually of relatively minor value.

The condition of larger assets such as transformers, reactors and capacitor banks is also monitored. The replacement, retirement or refurbishment options are evaluated which result in individual projects being raised to address the condition as required.

The condition based replacement programs and projects help to ensure the continued safety of employees, contractors, and the public, and to maintain a reliable electricity supply. The following table provides a list of substations where primary (HV) assets renewal or replacement projects have been identified:

Table 2.13: Planned substation primary (HV) asset renewal/replacement projects

Location	Area	Operational date required	Total estimated cost ($ million)
Wellington 330 kV Substation No.1 reactor replacement	Northern	Nov 2022	4.8
Forbes 132 kV Substation No.1 and No.2 transformer replacements	Central	Jun 2023	9.9
Sydney East 330 kV Substation No.2 and No.3 transformer replacements (bundled with other primary and secondary asset replacements)	Sydney	Dec 2021	26.5
Transformer renewals at Ingleburn, Kemps Creek, Liverpool, Moree, Murrumburrah, Panorama, Sydney North Substations	Across NSW	Feb 2025	TBA
Steelwork renewals at Sydney South/East/North, Albury, Dapto, Tomago, Hume and Wagga 132 kV Substations	Across NSW	Jun 2028	TBA
Transformer replacement or renewals being considered at various sites including Murray, Eraring, Darlington Point, Inverell, Gunnedah, Tumut, Taree, Yass, Tenterfield, Molong	Across NSW	Jun 2028	TBA
Capacitor bank renewals at various substations	Across NSW	Jun 2028	TBA
Reactor renewals at Sydney East and Lismore Substations	Across NSW	Jun 2028	TBA

2.4.3 Secondary systems

We continually strive to find leading solutions for managing the various facets of secondary systems which includes the protection, metering, control, communications, AC/DC supplies and alarm systems. New technologies such as IEC-61850 based automation solutions and MPLS-TP telecommunication systems, are under examination to further drive operational efficiencies.

To date, TransGrid has commissioned the first two IEC-61850 digital substation employing both process bus and station bus, utilising optical fibre cables between substation switchyards and relay rooms. TransGrid have also completed the final round of vendor testing for our future MPLS-TP telecommunication network which the deployment commenced late 2020.

TransGrid has an accredited Asset Management System to ensure that assets are managed in accordance with best practice. This provides assurance to stakeholders and the community that assets are being operated, maintained and replaced based on sound qualitative analyses to provide optimum benefits.

Strategies currently being rolled out will deliver benefits in the foreseeable future in areas such as reduced maintenance requirements, improved operational efficiencies, increased utilisation, improved visibility of assets, reduced life cycle cost and increased reliability. The following table provides a list of planned substation secondary assets requiring renewal and replacements:

Table 2.14:Planned substation secondary asset renewal and replacement projects

Location	Area	Operational date required	Total estimated cost ($ million)
Gadara Secondary System Renewal	South western	Nov 2021	5.4
Tamworth 330 kV Secondary Systems Renewal	Northern	Dec 2021	4.1
Coleambally Secondary Systems Renewal	South western	Jun 2022	2.6
Molong Secondary Systems Renewal	Central	Jun 2022	4.8
Tuggerah Secondary Systems Renewal HO	Newcastle and Central Coast	Sep 2022	6.0
Broken Hill Secondary Systems Renewal	South western	Nov 2022	18.7
Murrumburrah Secondary Systems Renewal	Southern	Mar 2023	9.7
Deniliquin Secondary Systems Renewal	South western	Apr 2023	12.8
Darlington Point Sec Systems Renewal	South western	Apr 2023	9.2
Wagga 330 kV Secondary Systems Renewal	Southern	Apr 2023	9.7
Ingleburn Secondary System Renewal	Sydney	May 2023	10.4
Muswellbrook Secondary Systems Renewal	Newcastle and Central Coast	Jun 2023	9.3
Liverpool Secondary Systems Renewal	Sydney	Jun 2023	6.9
Haymarket Secondary Systems Replacement	Sydney	Jun 2023	12.2
Wallerawang Secondary Systems Renewal	Central	Jun 2028	10.8
Lower Tumut Secondary Systems Renewal	Southern	Jun 2028	TBA
Regentville Secondary Systems Renewal	Sydney	Jun 2028	7.7
Panorama Secondary Systems Renewal	Newcastle and Central Coast	Jun 2028	7.3
Cowra substation Secondary Systems Renewal	Central	Jun 2028	8.5
Newcastle Secondary Systems Renewal	Newcastle and Central Coast	Jun 2028	14.0
Sydney east Secondary Systems Renewal	Sydney	Jun 2028	14.0
Vales point Secondary Systems Renewal	Newcastle and Central Coast	Jun 2028	13.9
Forbes Secondary Systems Renewal	Central	Jun 2028	8.0
Nambucca Secondary Systems Renewal	Northern	Jun 2028	8.2
Gunnedah Secondary Systems Renewal	Northern	Jun 2028	7.8
Tomago Secondary Systems Renewal	Newcastle and Central Coast	Jun 2028	14.0
Kempsey Secondary Systems Renewal	Northern	Jun 2028	TBA
Finley Secondary Systems Renewal	Southern	Jun 2028	6.9
Dumaresq Secondary Systems Renewal	Northern	Jun 2028	8.0
Kemps Creek Secondary Systems Renewal	Sydney	Jun 2028	TBA
Narrabri Secondary Systems Renewal	Northern	Jun 2028	TBA
Uranquinty Secondary Systems Renewal	Southern	Jun 2028	TBA

** Project includes some HV asset removals or replacements*

2.5 Asset retirements and deratings

Sydney East currently has four 330/132 kV transformers supplying the load in the surrounding area. Three of these are reaching their end-of-life. The 2018 demand forecast showed a decline in load growth such that it was not justifiable to replace all three transformers. It was decided that only two transformers will be replaced as shown in **Section 2.4.2**, and one will be retired.

One of the transformer replacements will be a new transformer, and the other will come from relocating a transformer from Rookwood Road to Sydney East.

TransGrid is not planning to retire or derate any other assets in our network over the next 10 years which would result in network constraints. The information reported in this section meets the requirement of NER Clause 5.12.2(c)(1A) and (1B).

Regulatory Investment Test for Transmission (RIT-T)

The importance of consulting with stakeholders to plan, develop and maintain the network to ensure it meets expectations now and into the future, is recognised by TransGrid. For significant augmentation and renewal investments, one of the methods for consultation is the Regulatory Investment Test for Transmission (RIT-T).

This process is designed to notify stakeholders of the investment need, examine network or non-network solutions, and invite the public to submit delivery proposals and advise stakeholders of the selection process.

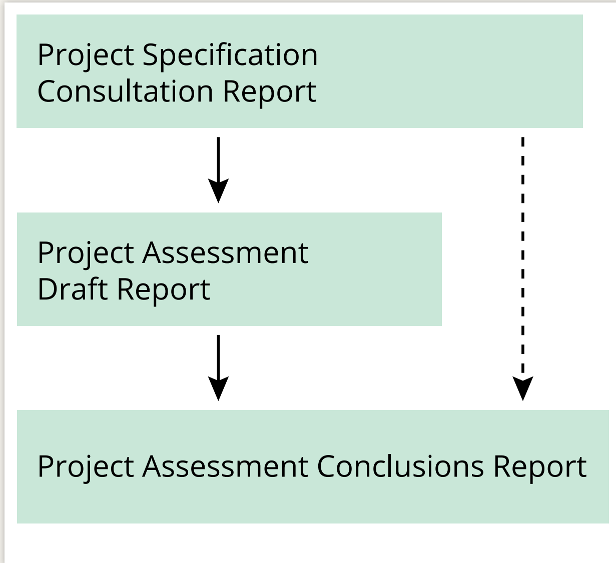
The RIT-T applies to transmission network investments where the cost of the most expensive credible option is greater than $6 million. It currently applies to all investments, except those relating to maintenance or urgent and unforeseen investments.

The RIT-T normally involves publication of three reports which highlight key milestones in the consultation process: the Project Specification Consultation Report (PSCR), the Project Assessment Draft Report (PADR) and the Project Assessment Conclusions Report (PACR). Minimum consultation periods following publication of the PSCR and PADR are specified and there is a requirement for submissions received in response to these documents to be considered. The PADR can be omitted under certain circumstances provided for in the NER.

For the category of 'replacement transmission network asset' there is a requirement to disclose information in annual planning reports which includes a brief project description, commissioning date, other reasonable options considered, estimated cost, and planned asset de-ratings and retirements.

TransGrid is presently drafting several PSCRs for asset condition-driven investments.

Figure 2.17: RIT-T consultation documents



2.6 Regulatory Investment Test for Transmission (RIT-T) schedule

TransGrid will be preparing a number of RIT-T assessments for the projects outlined in this chapter for the upcoming year with capital investment cost above $6 million.

The table below outlines the commencement dates for various RIT-Ts. This includes new RIT-Ts planned for 2021/22 and RIT-Ts that are underway with final RIT-T documents planned for publication later in the year.

Table 2.15: Active and planned RIT-T assessments

Project description	RIT-T Kick Off Quarter	Type of project
Managing asset risks at Sydney South substation	2018Q3*	Substation
Maintaining reliable supply to Broken Hill	2019Q4*	To be determined by RIT-T
Maintaining compliance with performance standards applicable to Broken Hill substation secondary systems	2019Q4*	Secondary Systems
Improving stability in South-Western NSW	2020Q2*	To be determined by RIT-T
Maintaining compliance with performance standards applicable to Liverpool Substation secondary systems	2020Q4*	Secondary Systems
Maintaining compliance with performance standards applicable to Darlington Point Substation secondary systems	2020Q4*	Secondary Systems
Supply to Bathurst, Orange & Parkes areas	2021Q1*	To be determined by RIT-T
Supply to the North West Slopes area	2021Q2*	To be determined by RIT-T
Managing safety and environmental risks on Line 18 (Kangaroo Valley-Dapto)	2021Q2	Transmission Line
Supply to Parkes area (short term)	2021Q3	Substation
Increase capacity for generation in the Molong to Parkes area	2021Q3	Transmission Line
Managing safety and environmental risks on Line 28 (Sydney North-Sydney East)	2021Q3	Transmission Line
Managing safety and environmental risks on Line 21 (Sydney North-Tuggerah)	2021Q3	Transmission Line
Maintaining compliance with performance standards applicable to Ingleburn Substation secondary systems	2021Q3	Secondary Systems
Managing safety and environmental risks on Line 11 (Sydney South-Dapto)	2021Q3	Transmission Line
Maintain voltage in Beryl area	2021Q3	Substation
Supply to Vineyard area	2021Q3	Substation
Managing safety and environmental risks on Line 27 (Sydney North-Sydney East)	2021Q4	Transmission Line
Supply to Western Sydney Priority Growth area	2021Q4	Substation and Transmission Line
Managing safety and environmental risks on Line 86 (Tamworth-Armidale)	2021Q4	Transmission Line
Maintain voltage in the Vineyard area	2021Q4	Substation

** Active RIT-T, TransGrid anticipates publication of the PADR/PACR during FY2022.*

A list of TransGrid's ongoing RIT-T consultations can be found at: https://www.transgrid.com.au/what-we-do/projects/regulatory-investment-tests/Pages/default.aspx

2.7 Changes from TAPR 2020

Updates in this chapter and referenced Appendices since TAPR 2020 includes the following:

- The RIT-T for maintaining reliable supply to Broken Hill commenced in 2019Q4, and was followed by the publication of the initial PADR in 2020Q3. In March 2021, the AER advised TransGrid that it should publish a revised PADR that takes into account the revised approach to the treatment of non-network options, and also take into account the benefits and costs of both the buy-side and the sell-side of the proposed transfer of ownership of the existing gas turbines at Broken Hill.
- The RIT-T for maintaining compliance with performance standards applicable to Broken Hill Substation secondary systems commenced in 2019Q4. Since publication of the PSCR, TransGrid identified a need to re-scope one of the credible options and identified one additional credible option. Consequently, the NPV analysis was re-run and presented in a PADR published in 2021Q1. TransGrid plans to publish a PACR later in 2021.
- In TAPR 2020 it was noted that the RIT-T for maintaining compliance with performance standards applicable to Ingleburn Substation secondary systems, had been deferred due to phasing of flood mitigation investigations. The flood mitigation investigations and solution development have progressed and an outcome is expected that will allow TransGrid to commence the RIT-T later in 2021.
- The RIT-T for managing asset risks at Sydney South substation commenced in 2018Q3. At the time the PSCR was published, TransGrid's cost estimate for refurbishing the gantries was primarily based on desktop assessment. Additional investigations and onsite trials were undertaken and updated costs were presented in a PADR published in Q42019. The PADR also presented an additional credible option which would result in a 45-year life extension. TransGrid is conducting further analysis to determine if the costs presented in the PADR reflect the final required scope of works to most effectively meet the need. Pending the outcome of the analysis and also confirmation regarding outages which may affect the proposed timing, TransGrid plans to publish a PACR later in 2021 or early in 2022.

These changes are consistent with the requirements of NER Clause 5.12.2(c), (1A), (1B), (3), (5), (6), (7), (8), and (11).

Chapter 3
Network support opportunities

- There are twelve locations where an estimated reduction in forecast load would defer a network constraint
- The expected changes at Broken Hill are likely to require non-network investment to maintain compliance with the NSW transmission reliability standards
- A Request for Proposals has been issued for non-network solutions for Maintaining reliable supply to Bathurst, Orange and Parkes areas
- A Request for Proposals has been issued for non-network solutions for Maintaining reliable supply to the North West Slopes area
- A Request for Tender has been issued for non-network solutions in Inner Sydney (Round 4)
- There are six locations where there may be potential to issue Requests for Proposals for non-network solutions in the next 10 years.

3.1 Opportunities for network support

The NSW transmission network is becoming more congested in weak areas as more spot loads and variable renewables connect.

The resultant load or generation is expected to lead to longer-term voltage constraints and/or thermal constraints in a number of regions. Our planning studies show that network support may be able to assist with maintaining voltage stability and ensuring power flows on transmission lines and equipment stay within their ratings.

In recent years, renewable generator connections in these weak areas have partially offset some of that load growth. However, the dispatch of additional renewable generation in these areas is likely to be limited by these same constraints (congestion) without any investment.

We have identified the potential for network support to assist with deferring twelve constraints over the next ten years.

The intent to issue Requests for Proposals (RfP) is set out in **Section 3.1.1**, where we have combined some constraints.

Both NER Clause 5.12.2(c)(4) and the Transmission Annual Planning Report Guidelines require TransGrid to report the subset of forecast constraints, identified in **Chapter 2**, where an estimated reduction in forecast load would defer a forecast constraint for a period of 12 months. The 'TAPR data' for the subset of forecast constraints is shown in **Table 3.1**.

Table 3.1: Forecast constraint information

Constraint or anticipated constraint	Proposed timing	Annual deferral value	Demand reduction required to defer investment by 1 year
Supply to the Broken Hill area (reliability)	2022	$5.76m, depending on timing and size of spot loads	50 -270 MW
Parkes voltage constraint	2022/23	$26-$32m (combined)	25 MW or 35 MVAr
Bathurst/Orange voltage constraint	2022/23		30 MW or 15 MVAr
Wellington thermal constraint	2024/25		18 MW
Maintaining reliable supply to the Beryl Area	2023	To be assessed	To be assessed
Gunnedah voltage constraint	2024/25	$12.4m (combined)	20 MVAr
Narrabri/Gunnedah voltage/thermal constraint (combined)	2024/25		29 MW
Narrabri voltage constraint	2028/29		50 MVAr
Vineyard voltage constraint	2024	$2.4m	59 MW or 40 MVAr
Sydney West BSP Supply (thermal transformer constraint)	2024	To be assessed	197 MW
Vineyard BSP Supply (thermal transformer constraint)	2028	$0.9m	48 MW
Beaconsfield BSP supply (thermal transformer constraint)	2030	$0.59m	200 MW

3.1.1 Requests for Proposals

TransGrid plans to issue RfP/EOIs for augmentation, replacement of network assets, or non-network options for the constraints listed in **Table 3.2**.

Table 3.2: Anticipated issue of a RfP

Constraint or anticipated constraint	Intent to issue RfP/EOI	Load reduction required	Constraint Date	Release Date
Powering Sydney's Future	RfT – Round 4 (Final): SR6229296	30-55 MW	Summer 2021/22	July 2021
Maintaining reliable supply to Bathurst, Orange and Parkes areas • Parkes voltage constraint • Bathurst/Orange voltage constraint • Wellington thermal constraint	Issued: SR4055874	Up to 90 MW or 150 MVAr	2022/23	17 March 2021
Maintaining reliable supply to the North West Slopes area • Gunnedah voltage constraint • Narrabri voltage constraint • Narrabri/Gunnedah voltage/thermal constraint (combined)	Issued: SR5385504	Up to 52 MW and 50 MVAr	2024/25	21 April 2021
Maintaining reliable supply to the Beryl Area	To be assessed	To be assessed	2023	To be assessed
Maintaining reliable supply to the Vineyard Area • Vineyard voltage constraint • Vineyard BSP Supply (thermal transformer constraint)	To be assessed	To be assessed	2024	To be assessed
Maintaining reliable supply to the Sydney West Area • Sydney West BSP Supply (thermal transformer constraint)	To be assessed	To be assessed	2025	To be assessed

3.2 Changes from TAPR 2020

Updates in this chapter and referenced Appendices since TAPR 2020 include:

- Release of RFP/EOI for Maintaining reliable supply to Bathurst, Orange and Parkes areas, and North West slopes.
- Twelve network support opportunities have been updated.

Chapter 4

Forecasts and planning assumptions

- NSW & ACT energy consumption is forecast to grow at an average rate of 0.5 per cent per annum over the next ten years, after an initial decline due to the ongoing effects of COVID-19
- Summer maximum demand is expected to grow by around 1.1 per cent per annum and the winter maximum demand by around 0.4 per cent per annum on average
- 1477 MW of new renewable generation has committed to connect at various locations in NSW since June 2020.

4.1 Key highlights

4.1.1 Supply

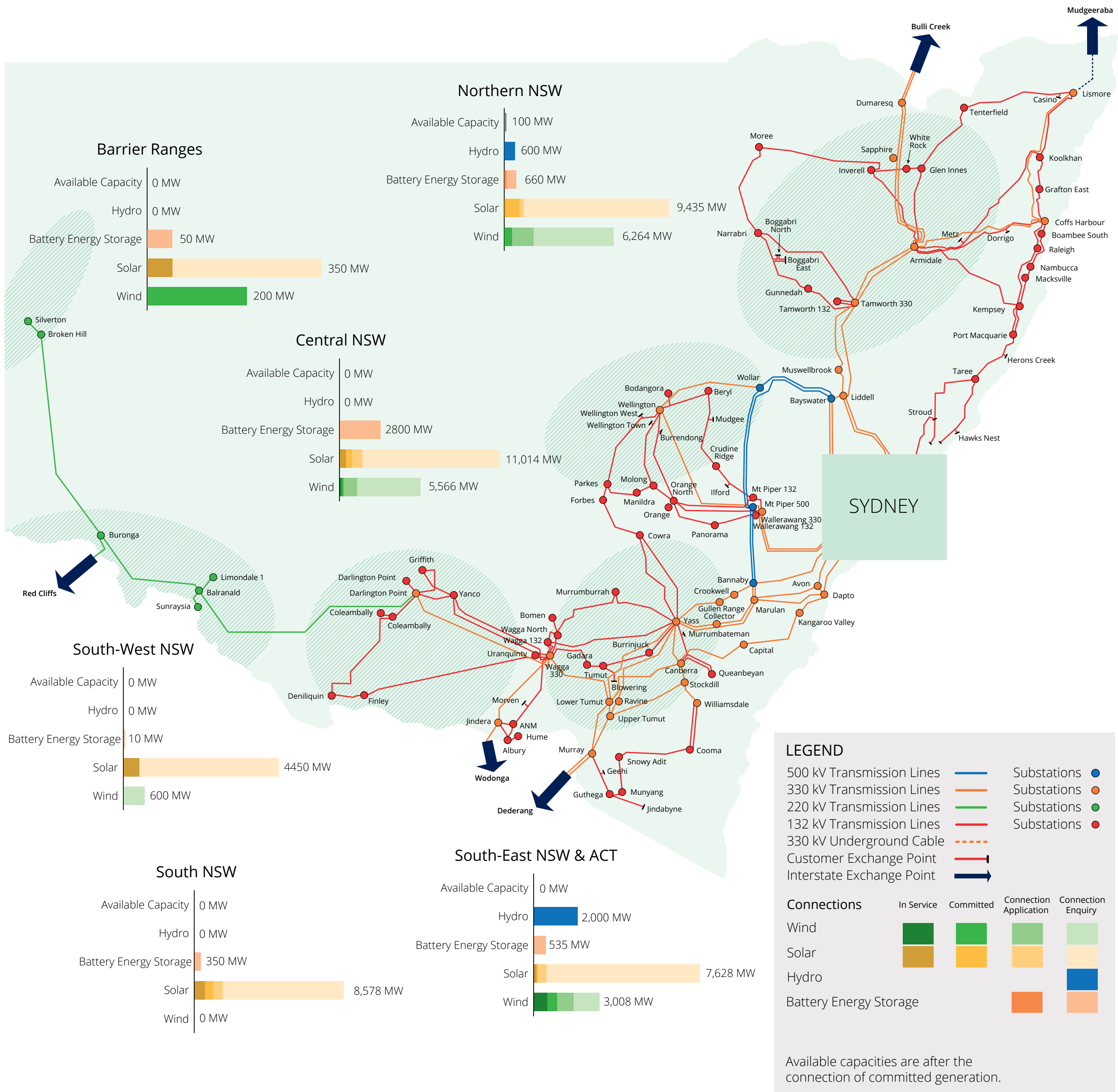
Since the publication of TAPR 2020, in June last year, more generation proponents have signed connection agreements, this has been incorporated in this planning review as committed generation.
This includes:

- 1240 MW of solar generation capacity; and
- 237 MW of wind generation capacity.

We expect further generation proponents to sign connection agreements over the next 12 months as projects advance through the connection process.

We continue to receive connection enquiries for projects at various stages of development across NSW. Only a fraction of this proposed generation can be accommodated in TransGrid's current network due to declining spare capacity. The approximate available network capacity for generation connections in NSW is presented in **Figure 4.1**.

Figure 4.1: NSW transmission connection activity 2016-2020



4.1.2 Demand

Demand growth has been flat or falling in recent years and growth will most likely remain weak over a 10-year forecast horizon, as shown in **Table 4.1**.

Table 4.1: NSW region medium scenario energy and demand (compound average annual growth rates)

	Actual/estimated 2015-16 to 2020-21 (2015 to 2020 for winter)	Forecast 50% POE 2021-22 to 2030-31 (2021 to 2030 for winter)
Annual energy	-0.9%	0.5%
Maximum demand (Summer)	-1.6%	1.1%
Maximum demand (Winter)	-0.1%	0.4%

4.2 TransGrid 2021 NSW region forecast

4.2.1 Introduction

Demand forecasts for the NSW region over a 10 year horizon under three scenarios: medium growth (or most likely), high growth and low growth.

The following sections describe the sources and assumptions behind the demand forecast and present the detailed forecast outcomes.

4.2.2 Definitions, assumptions and inputs

The forecasts include annual energy in GWh, summer maximum demand (MD) in MW and winter MD in MW. These measures are presented in terms of demand on the transmission network. This is measured by the output of all NEM connected scheduled, semi-scheduled and non-scheduled generating units. The sum of output from all these types of generating units is termed "native" energy or demand.

Generation measured at generator terminals includes any power used for generator auxiliaries and is termed "as generated". Generation measured at the point of connection with the network is termed "sent out". In this report, energy is on a sent out basis and MDs are on an as generated basis.

MDs are half-hourly averages and are highly dependent on the prevailing weather. High temperatures on summer afternoons and low temperatures on winter evenings typically produce half-hourly demand peaks. To account for the imprecise nature of long range weather forecasting, forecast MDs are prepared in terms of 10 per cent probability of exceedance (10% POE), 50 per cent probability of exceedance (50% POE) and 90 per cent probability of exceedance (90% POE). POE delineates the frequency with which probable demand is expected to exceed the stated level. For example, a 10% POE level of demand is expected to be exceeded 10 per cent of the time (i.e. once in every 10 years).

Around 18 per cent of TransGrid's load is accounted for by a handful of large industrial or mining customers, all of which are connected at very high voltages and some directly to the transmission network.

These customers are not generally subject to incremental change as a result of economic conditions or population growth and are typically not sensitive to weather. As a result, these are not included in the forecast modelling process but are added back into the forecast at the end. The future large industrial load is reviewed every year with inputs from all major industrial load customers.

Forecasts have been prepared based on top-down models of underlying consumer behaviour, in the absence of recent above-trend energy efficiency, using measures of energy services for eight distinct industry sectors. This measure includes the impacts of estimated energy efficiency and distributed energy resources (DER), including small-scale photovoltaic (PV) generation and stationary and electric vehicle charging/discharging.

To prepare the forecasts, we used projections of population, economic growth, retail electricity price, policy and program driven energy efficiency impacts and various DER components. Small projected changes to certain large mining, commercial and industrial loads including spot loads were informed by TransGrid customer data. The projections of DER and spot loads were used to modify modelled forecasts of underlying consumer demand.

Further information on the method of preparation for the forecast and a review of previous forecast accuracy is in **Appendix 1**.

4.2.3 Demand drivers

Underlying consumer demand for electricity is traditionally understood to be driven by population and economic growth, and energy prices, in the long term, and by weather in the short term. In the past decade however, a coincidence of energy efficiency, take up of DER and rising electricity prices acted to moderate demand. In preparing the NSW region demand forecasts, TransGrid has therefore considered the combined impacts of underlying consumer behaviour, energy efficiency and DER on the transmission network.

The forecasts are determined from a measure of "energy services" which is derived as all energy consumed plus an estimate of recent above-trend energy efficiency. The electricity proportion of energy services therefore consists of grid-supplied energy or demand (plus network losses), out of trend energy efficiency, PV generation, and the effects of battery charging and discharging, including electric vehicle charging. While the empirical relationship between grid-supplied electricity on the one hand, and prices and economic growth on the other, may appear to unreliable, energy services remains capable of being reliably and consistently modelled.

TransGrid models residential and non-residential energy separately. The non-residential sector is further broken down into agriculture, mining, manufacturing, utilities, construction, commerce and transport. In these models, population, household disposable income (HDI), residential electricity and gas prices and temperature drive residential energy demand. Industry Gross Value Added (GVA), non-residential electricity and gas prices and temperature generally drive non-residential demand. Further detail on TransGrid's modelling approach and results is shown in **Appendix 1**. TransGrid's models predict that:

- a one per cent increase in HDI will lead to an increase in residential energy of 0.71 per cent;
- a one per cent increase in GVA will lead to increases in non-residential energy ranging between 0.33 per cent (utilities) and 2.13 per cent (mining);
- a one per cent increase in the residential energy price will lead to a decrease in residential energy use of 0.55 per cent; and
- a one per cent increase in non-residential energy prices will lead to decreases in non-residential energy ranging from 0.08 per cent (commercial) to 0.84 per cent (manufacturing).

The models also predict small positive increases in electricity consumption as a result of an increase in gas prices, due to longer term fuel switching, and hotter or colder than average temperatures due to short term cooling and heating of buildings.

TransGrid obtained independent projections of population and economic growth[30], as well as electricity and gas prices[31]. TransGrid also obtained independent advice on the expected take-up by both residential and non-residential consumers of distributed energy resources (rooftop PV generation and accompanying battery storage[32], and externally charged electric vehicles[33]) and their associated load effects on the power system. There may be some interaction between the various distributed resources, in which case these effects may be underestimated. For example, there is evidence that electric vehicles may improve the payback for installing residential rooftop PV systems, which would increase the take-up of such systems above TransGrid's forecast allowance.

TransGrid obtained independent advice[34] on the impact of various energy efficiency programmes and policies to construct measures of electricity services for modelling purposes. The above-trend element of energy efficiency was subsequently removed from the modelled energy and maximum demand forecasts to identify the expected grid impact. It may be the case that, in addition to the pure price impacts allowed for in TransGrid's models, there could be "rebound" effects from increased energy efficiency, increased PV self-generation or the use of battery storage resulting in lower energy bills. TransGrid did not independently assess the potential for such rebound effects in line with recent AEMO forecasting practice did apply a 20 per cent discount to the estimated energy efficiency effects.

4.2.4 Temperature sensitivity

TransGrid's analysis of variation of maximum demand with temperature reveals that temperature sensitivity in summer 2020/21 was 395 MW per degree increase in the average daily temperature, which represents a doubling in sensitivity in percentage terms in the last 25 years.

The winter temperature sensitivity has increased relatively little in that time and is estimated to have been 215 MW increase per degree reduction in average daily temperature in 2020.

4.2.5 Climate change

TransGrid assumes that Australia will meet its existing obligation to reduce national greenhouse emissions by 26 per cent on 2005 levels by 2030. Existing renewable certificate schemes (the Small-scale Renewable Energy Target and the Large-scale Renewable Energy Target) and State based renewable energy schemes will contribute to the emissions reduction target, as will the planned closure of coal-fired power stations. Steady increases in renewable generation and withdrawal of non-renewable generation in large increments will affect the wholesale price of electricity and therefore indirectly affect demand.

Projected increases in future average temperatures of around 0.5 degrees every 10 years are consistent with NSW average temperature trends over the last 20 years. This will make a small but significant contribution to annual energy and summer demand growth, and will detract from winter demands.

30 BIS Oxford Economics (2021) Economic Forecasts to 2039 – NSW and ACT, Final, April 2021, report to TransGrid.
31 Jacobs (2021) TransGrid Retail Electricity Price Forecasts, Final Report, March 2021, report to TransGrid.
32 Jacobs (2021) Rooftop PV and Battery scenarios, April-May 2021, report to TransGrid.
33 Energeia (2021) Electric Vehicle Modelling, March 2021, report to TransGrid.
34 Energy Efficient Strategies (2021) Impact of Energy Efficiency Programs on Electricity Consumption in NSW and the ACT from 2000 to 2040, Final Report, May 2021.

4.2.6 The post-COVID economic recovery and outlook for load growth

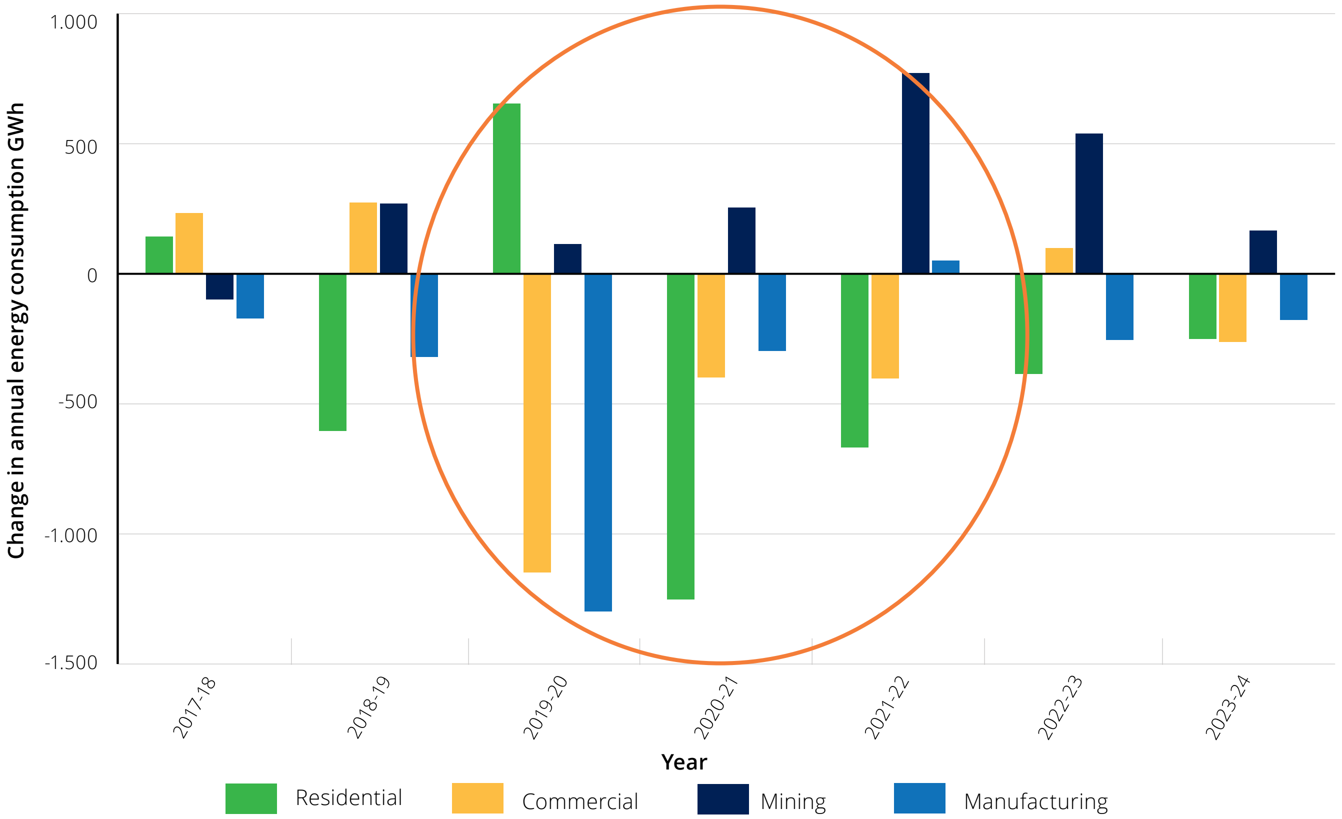
The Australian economy suffered a steep downturn in the first half of 2020, with a cumulative decline in GDP during the period between March and June pushing GDP for financial year 2019/20 into a -0.2 per cent recession. However, as advised by BIS Oxford Economics[35], the NSW economic bounce back during the second half of 2020 was stronger than the forecast underlying our 2020 TAPR load forecast. The rebound reflected the relaxation of people movement and trading restrictions, as well as the impact of fiscal and monetary stimulus, with households in particular benefiting from support payments. With the withdrawal of some fiscal stimulus during 2021, the pace of economic growth after the initial rebound will be naturally slower.

The economic modelling in this report does not take into consideration the impact of the July 2021 lockdown in NSW due to the ongoing COVID-19 outbreak. It is likely that non-residential energy consumption will be impacted due to closure of a number of commercial and business establishments which will be partly offset by a rise in residential consumption. A preliminary look at the July 2021 consumption data did not reveal any major downturn. TransGrid will continue to monitor the impact of the lockdown on energy consumption.

Australia's slow vaccine roll-out and the expected delay in opening international borders will increase economic uncertainty, especially for the all-important tourism, education services and related industries and in-bound permanent migration.

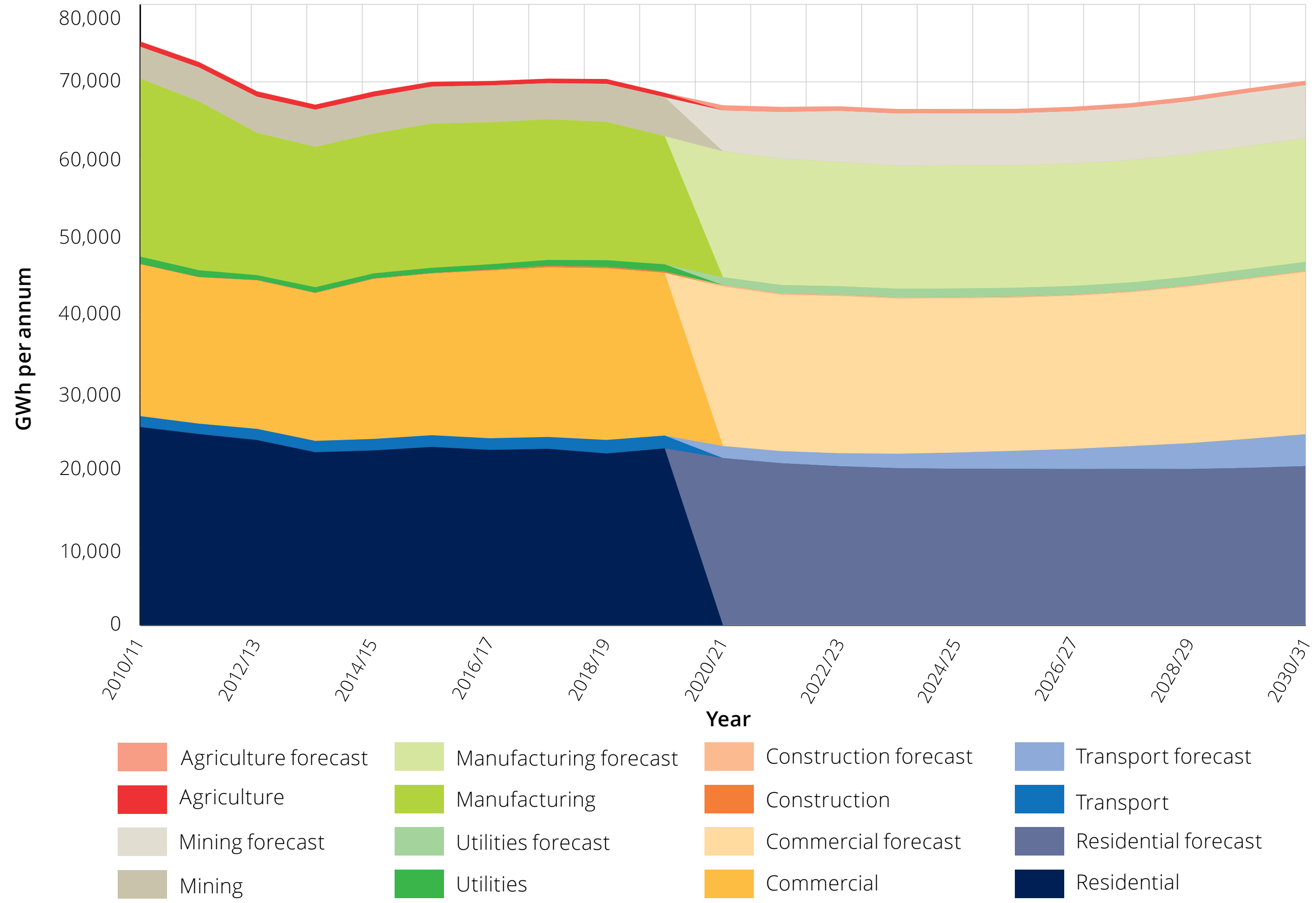
Overall energy supplied by TransGrid to NSW region electricity consumers during 2019/20 fell by 2.5 per cent, but as shown in **Figure 4.2** this fall would have been greater had it not been partially offset by growth in the residential sector. Consumption in this sector was supported by continued growth in household income, but also likely reflects an increase in working from home. Our forecast suggests that residential energy consumption will resume its downward trend as a proportion of total electricity in NSW from 2020/21 onwards, and that mining investment will lead the moderate growth in energy consumption. The moderate outlook for energy consumption over the next ten years is a consequence of the expected gradual recovery in economic conditions as well as on-going growth in small-scale rooftop PV installation and the effects of energy efficiency measures.

Figure 4.2: Short term changes in energy consumption in NSW region



NSW region grid-supplied electricity use between 2022 and 2031 will fall slightly for most sectors with the notable exceptions of mining and transport. **Figure 4.3** shows NSW region sectoral grid electricity consumption in historical context and an outlook for the 10 year forecast period. There is a long-run decline in the share of residential and manufacturing electricity consumption and a somewhat offsetting increase in commercial consumption. Much of the decline in electricity consumption in the residential and manufacturing sectors and a restrained commercial sector growth represents increased energy efficiency and small-scale PV installation. However, this also reflects the net effects of switching from gas to electricity and an increasing share of economic activity being driven by the commercial sector, relative to manufacturing. Mining is forecast to increase its share in the short-run due to planned mining investments. The expansion of transport electricity use towards the end of the forecast period is also notable and reflects a forecast increase in electric vehicle charging.

Figure 4.3: Industry composition of NSW region annual energy consumption (actual and medium forecast)



35 BIS Oxford Economics (2021) Economic Industry and Dwelling Forecasts to FY2040 – NSW and ACT, Report prepared for TransGrid, May 2021.

4.2.7 Forecast scenarios

The annual energy and maximum demand models are conditional on a number of input variables. Each of these inputs is varied in correspondence to either the medium, high or low energy scenario. TransGrid judges the probability of the future approximating the medium scenario to be greater than the probability of either the high or low scenario.

The medium, high and low annual energy forecasts result from use of the corresponding input variables. The maximum demand forecasts are derived in part from the forecast annual energy growth forecast and in part from extensive analysis of maximum demand-temperature relationships. The load forecasts are therefore driven by the inputs provided by each scenario.

A summary of the three scenarios is presented in **Table 4.2**.

Table 4.2: Scenario inputs*

Input Variables	Medium energy scenario	High energy scenario	Low energy scenario
Population growth (average 2021/22 to 2030/31) %	1.1	1.5	0.6
Real household disposable income (average 2021/22 to 2030/31) %	2.0	2.8	1.4
Economic growth GSP (average 2021/22 to 2030/31) %	2.3	3.2	1.6
Real residential electricity price (average 2021/22 to 2030/31) %	0.8	0.1	1.6
Real non-residential electricity price (average 2021/22 to 2030/31) %	0.7	-0.2	1.7
Real price of gas and other fuels (average 2021/22 to 2030/31) %	3.2	3.4	3.1
Average temperature increase (average 2021/22 to 2030/31), degrees	0.5	0.5	0.5
Additional energy residential efficiency savings in 2030/31 (compared to 2021/22), GWh	2,447	2,447	2,447
Additional energy non-residential efficiency savings in 2030/31 (compared to 2021/22), GWh	4,383	4,383	4,383
Residential rooftop PV generation in 2030/31, GWh	6,105	6,319	5,651
Non-residential rooftop PV generation in 2030/31, GWh	2,483	2,689	2,288
Stationary battery net charging in 2030/31, GWh	97	136	78
Vehicle battery charging in 2030/31, GWh	2,201	2,775	1,381

** Note: Compound average growth rates where shown as %.*

4.2.8 Annual energy forecasts

Figure 4.4 and **Table 4.3** show annual energy forecasts for the medium, high and low scenarios. Energy sent out reached its highest point over 10 years ago and has fallen since 2018/19 largely due to continuing increases in rooftop PV, the effects of energy efficiency measures and in the context COVID-19 restrictions.

Over the forecast horizon, the main drivers of change are:

- a resumption in relatively moderate population and economic growth following the current COVID-19 related downturn;
- an increase in spot loads due to new mining loads;
- falls in retail electricity prices following downward pressures on wholesale electricity prices due to a decline in the cost of renewable technologies;
- a small but significant increase in electric vehicle charging towards the end of the forecast horizon; and
- offsets to growth as a result of existing and new energy efficiency programs and the growing uptake of small-scale rooftop PV systems.

Figure 4.4: NSW region sent-out annual energy consumption (GWh) forecast

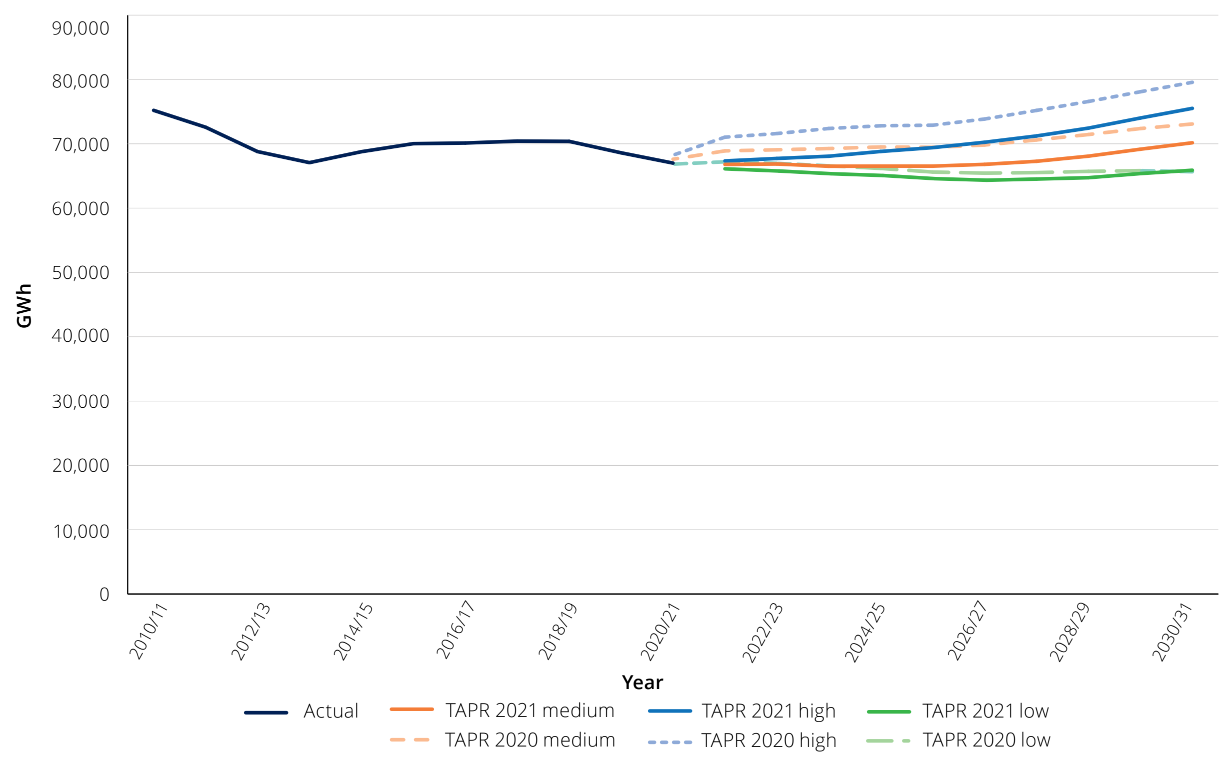


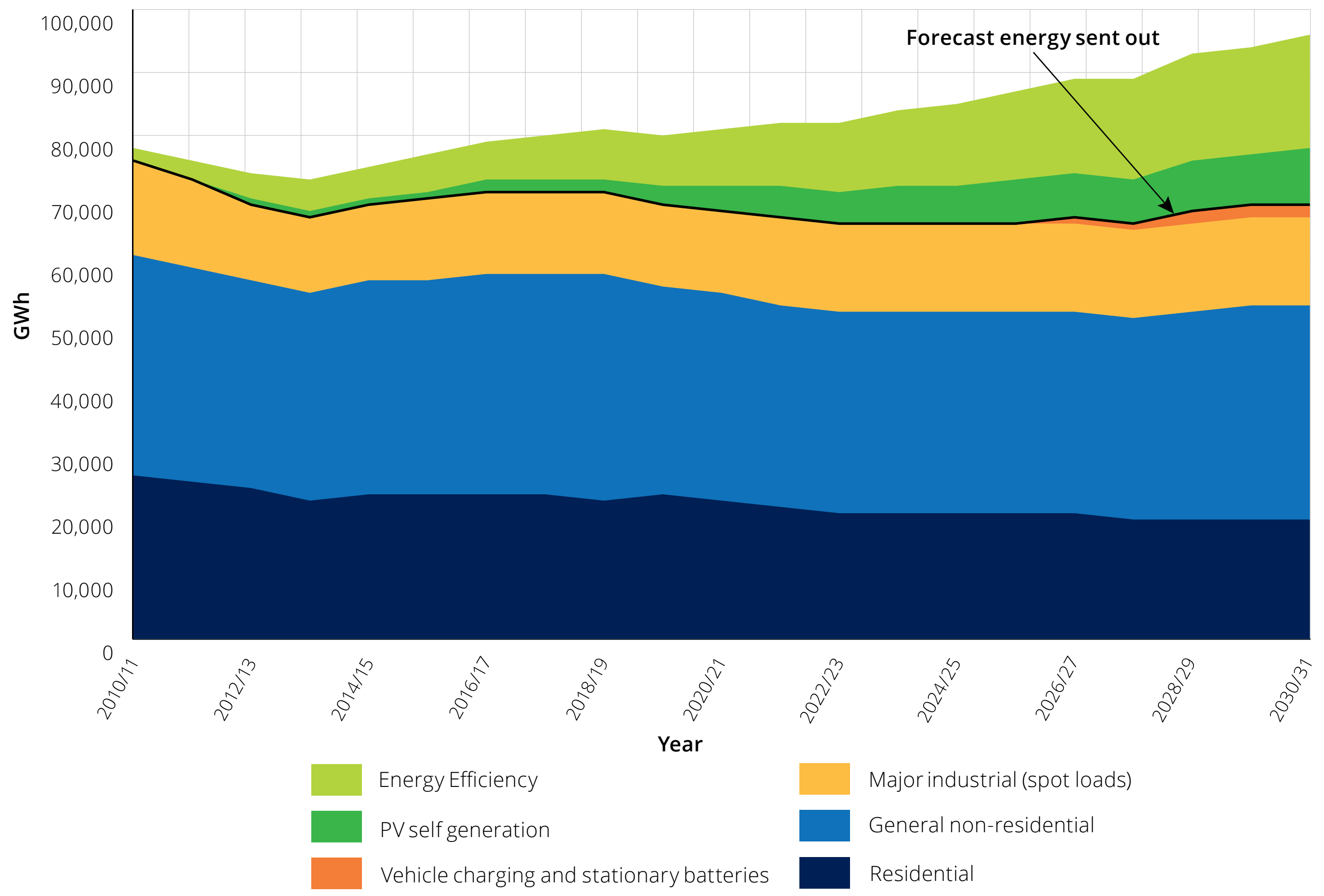
Table 4.3: NSW region sent-out annual energy consumption (GWh) forecast

	Actual	Medium	High	Low
2014/15	68,766			
2015/16	70,020			
2016/17	70,120			
2017/18	70,423			
2018/19	70,376			
2019/20	68,600			
2020/21 (est.)	67,000			
2021/22		66,790	67,340	66,110
2022/23		66,860	67,720	66,120
2023/24		66,510	68,070	65,700
2024/25		66,530	68,810	65,420
2025/26		66,530	69,400	64,930
2026/27		66,800	70,240	64,690
2027/28		67,280	71,220	64,520
2028/29		68,080	72,440	64,730
2029/30		69,160	74,010	65,370
2030/31		70,160	75,510	65,890
Compound Average Growth Rate 2021/22 – 2030/31		0.5%	1.3%	0.0%

Figure 4.5 shows the composition of historic energy and the medium growth forecast. A significant proportion of the decline in energy consumption in the initial years of the forecast period is accounted for by the non-residential sector as a result of disruption to small industrial/commercial loads due to COVID-19. The longer-term historical trend of a declining residential share of energy consumption is also apparent in the forecast. A large amount of potential load increase has been, and is forecast to be, offset by accelerated energy efficiency and small-scale rooftop PV take up.

Meanwhile, the impact of battery charging on annual energy is projected to remain modest over the forecast horizon. Under the medium scenario, there is minimal effect of COVID-19 on major industrial loads and these are expected to increase at a modest pace due to additional mining loads.

Figure 4.5: Composition of NSW region annual energy consumption (actual and medium forecast)



4.2.9 Summer maximum demand forecast

Figure 4.6 and **Table 4.4** show summer maximum demand (MD) forecasts for the medium, high and low scenarios. The forecasts include the 10%, 50% and 90% POE levels for each scenario. Summer MD has moderated in the past year due to higher uptake of rooftop PV (causing lower grid demand) and mild weather conditions during the 2020/21 summer period.

Over the forecast horizon, the main drivers of change are:

- moderation in underlying growth as reflected in the energy forecast;
- continued – albeit moderating – growth in air-conditioning use, as air-conditioning ownership gets closer to saturation;
- offsets to growth from energy efficiency, roof-top PV generation and net battery discharging, in combination with the fixed or variable timing of these resources; and
- continued rises in summer average temperatures (as evident from historical summer temperature data) and the effects of global warming.

Figure 4.6: NSW region summer as-generated maximum demand (MW) medium forecast

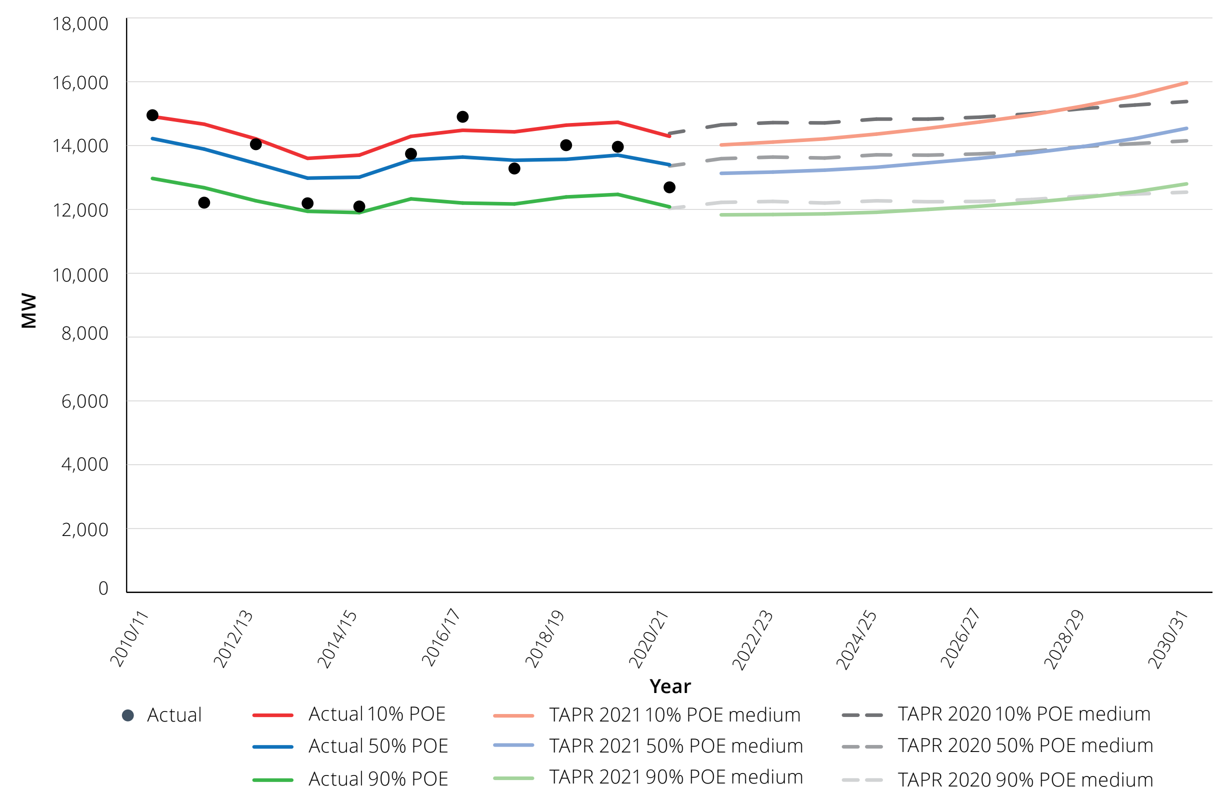


Table 4.4: NSW region summer as-generated maximum demand (MW) forecast

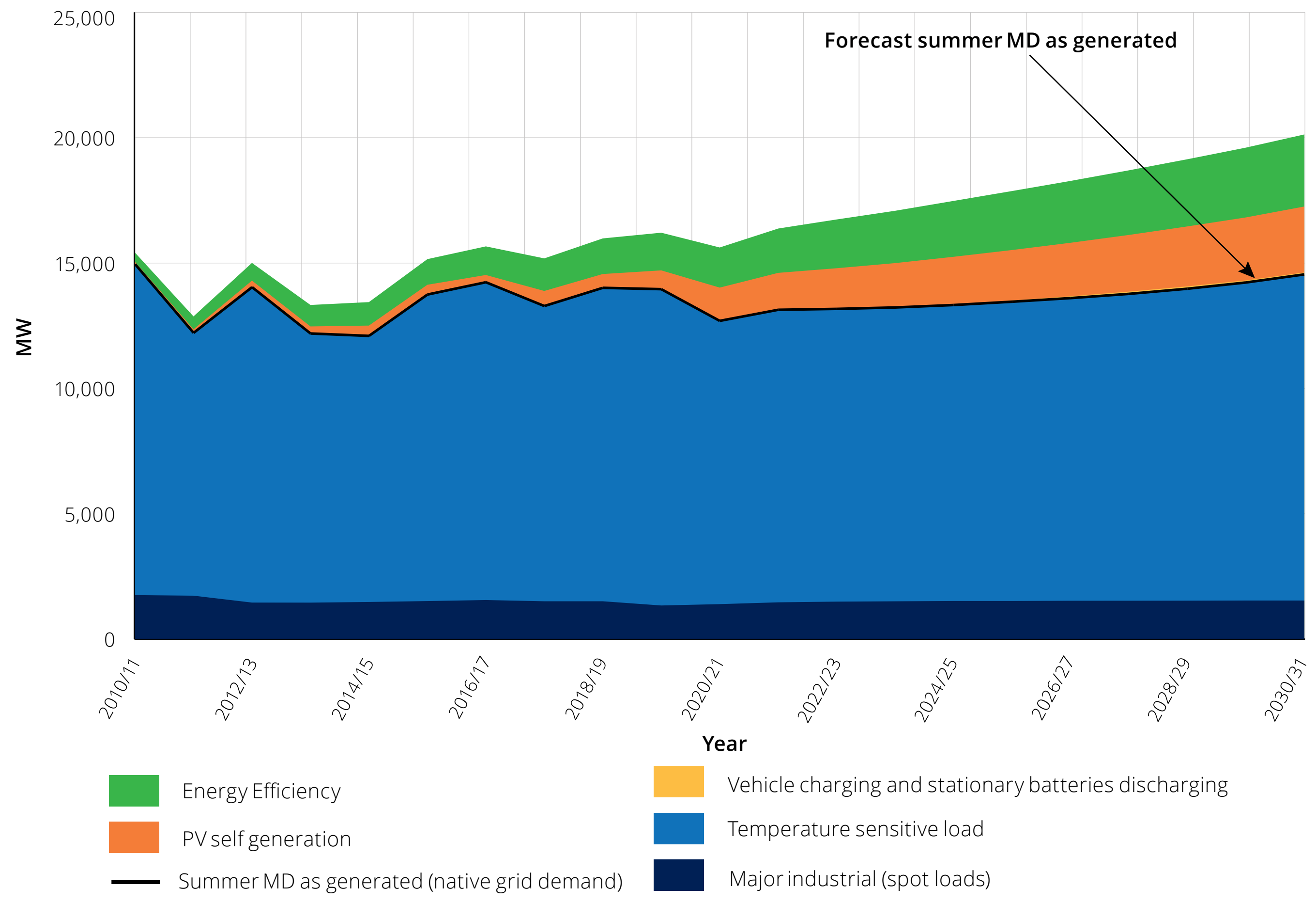
	Actual	Medium			High			Low		
		10% POE	50% POE	90% POE	10% POE	50% POE	90% POE	10% POE	50% POE	90% POE
2014/15	12,093	13,705	13,013	11,900						
2015/16	13,742	14,286	13,545	12,334						
2016/17	14,859*	14,485	13,638	12,196						
2017/18	13,284	14,432	13,544	12,175						
2018/19	14,010	14,638	13,572	12,393						
2019/20	13,957	14,732	13,698	12,475						
2020/21	12,692	14,288	13,397	12,083						
2021/22		14,020	13,130	11,830	14,110	13,200	11,890	13,870	13,000	11,720
2022/23		14,110	13,170	11,840	14,320	13,330	11,970	13,900	12,990	11,680
2023/24		14,210	13,230	11,860	14,640	13,570	12,140	13,970	13,030	11,690
2024/25		14,360	13,320	11,910	15,040	13,870	12,360	14,040	13,060	11,690
2025/26		14,540	13,460	12,000	15,420	14,160	12,570	14,060	13,050	11,660
2026/27		14,740	13,600	12,100	15,790	14,450	12,790	14,070	13,040	11,620
2027/28		14,960	13,770	12,220	16,180	14,750	13,000	14,080	13,020	11,590
2028/29		15,240	13,970	12,370	16,590	15,060	13,230	14,160	13,070	11,610
2029/30		15,560	14,220	12,550	17,050	15,410	13,480	14,330	13,190	11,690
2030/31		15,970	14,540	12,800	17,560	15,800	13,780	14,600	13,410	11,850
Compound Average Growth Rate 2021/22 – 2030/31		1.5%	1.1%	0.9%	2.5%	2.0%	1.7%	0.6%	0.3%	0.1%

Note: 2016/2017 Summer MD (on 10 February 2017) was recorded as 14,233 MW at a time of substantial load curtailment. Estimated MD in the absence of such curtailment was 14,859 MW.

Figure 4.7 shows the composition of historic summer MD and the medium growth forecast. A significant amount of potential load increase in the grid has been, and will continue to be, offset by accelerated energy efficiency and small-scale rooftop PV take up. In recent years, PV has pushed back the time of the network maximum demand. The forecast growth in PV, although considerable, will be less likely to push this time later into the evening during the forecast horizon.

Hence future additions to PV capacity are anticipated to have a proportional effect in reducing summer maximum demand on the power network. In the later forecast years, distributed battery discharging is forecast to generally occur after the time of the network peak, so the relatively small capacity of batteries forecast to be installed will not act to depress grid maximum demand in summer.

Figure 4.7: Composition of NSW region summer MD (actual and 50% POE medium forecast)



4.2.10 Winter maximum demand forecast

Figure 4.8 and **Table 4.5** show winter maximum demand (MD) forecasts for the medium, high and low scenarios. The forecasts include the 10%, 50% and 90% POE levels for each scenario. Winter MD has increased at a lower rate than summer MD, in part because average winter temperatures have been quite mild in the past few years.

Over the forecast horizon, the main drivers of change are:

- decline and moderation in underlying growth as reflected by the energy forecast;
- offsets to growth from energy efficiency and net battery discharging at the time of the evening winter network peak, in combination with the fixed or variable timing of these resources; and
- comparative cost of using electrical appliances for heating (reverse cycle air conditioners) versus those using competing fuels like natural gas.

Figure 4.8: NSW region winter as-generated maximum demand (MW) medium forecast

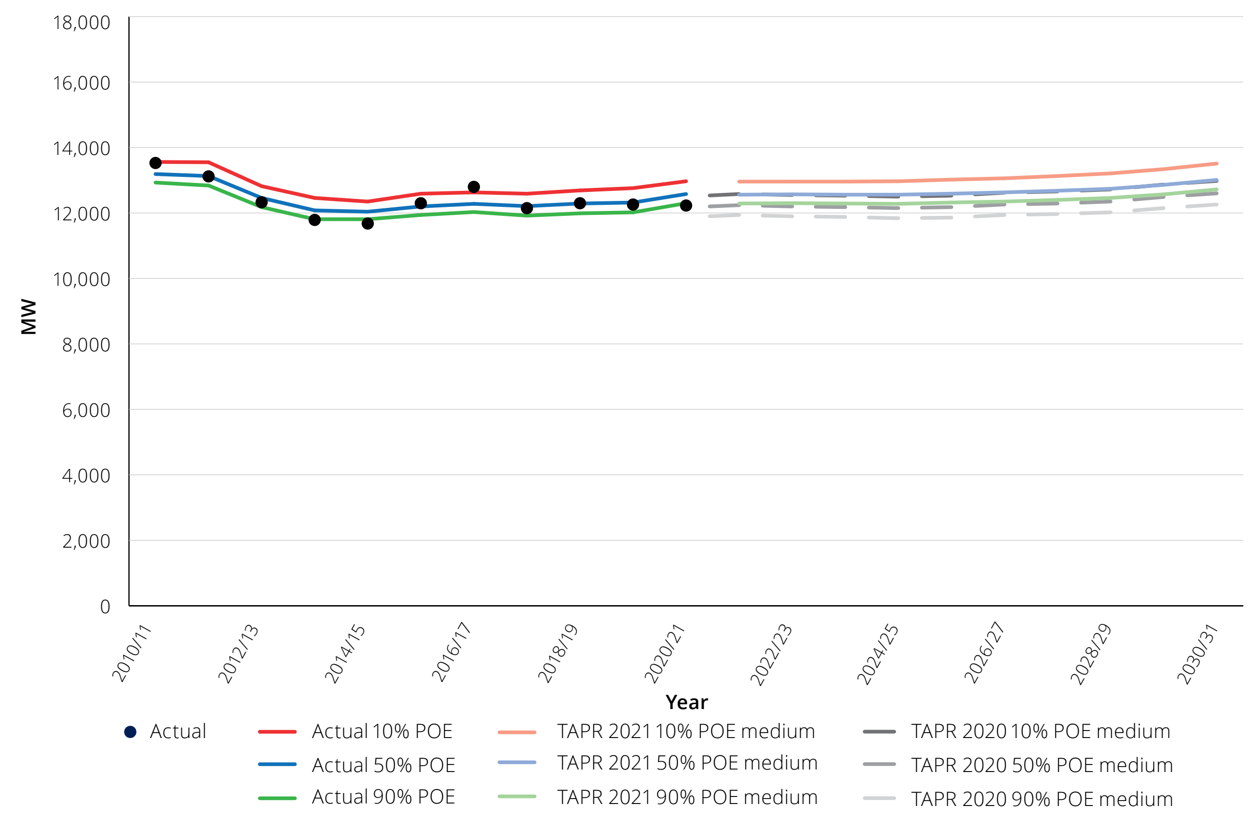


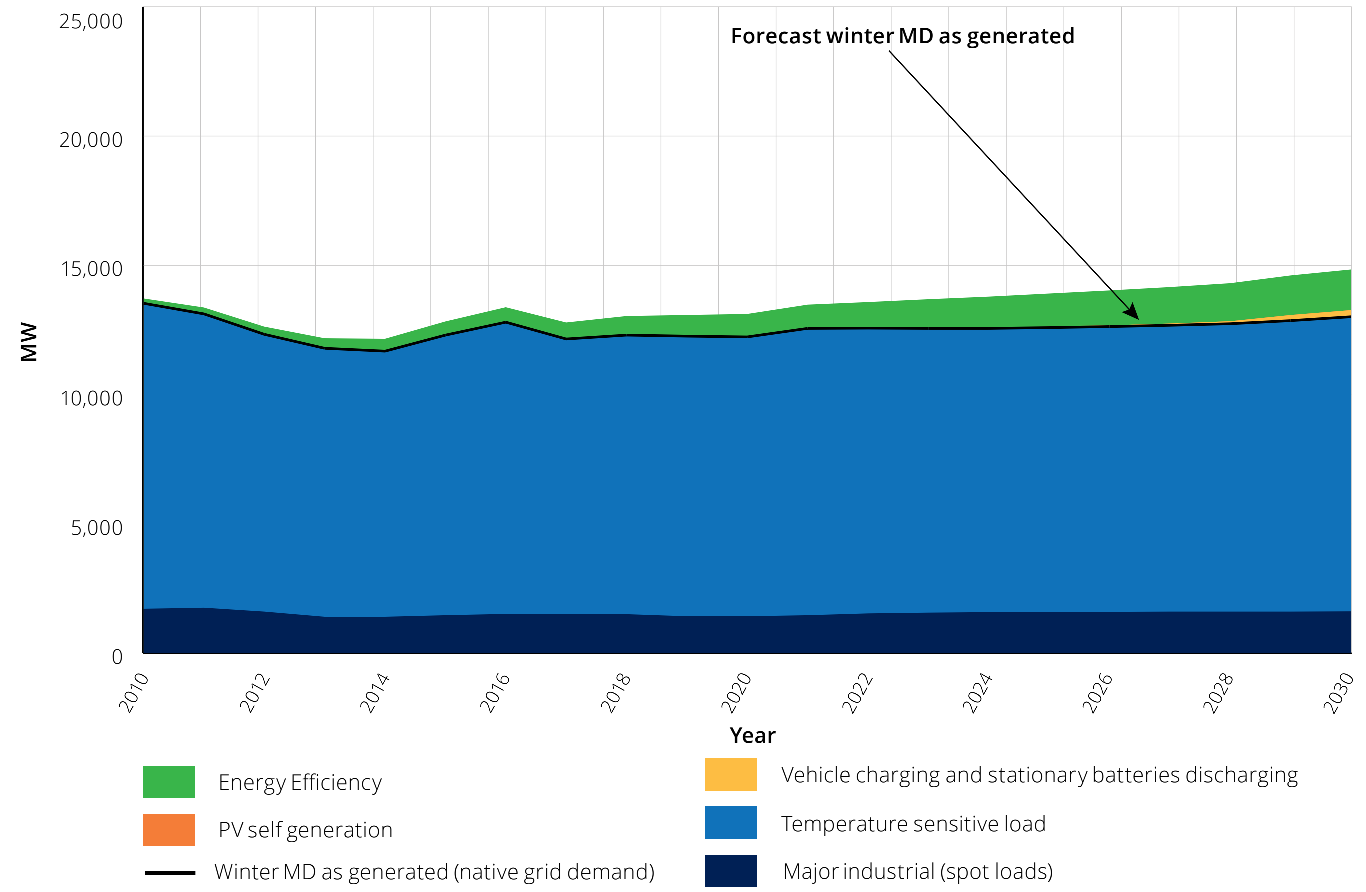
Table 4.5: NSW region winter as-generated maximum demand (MW) forecast

	Actual	Medium			High			Low		
		10% POE	50% POE	90% POE	10% POE	50% POE	90% POE	10% POE	50% POE	90% POE
2014	11,677	12,318	12,010	11,783						
2015	12,298	12,559	12,174	11,913						
2016	12,802	12,598	12,254	11,999						
2017	12,150	12,563	12,184	11,889						
2018	12,304	12,659	12,261	11,964						
2019	12,261	12,727	12,293	11,990						
2020	12,233	12,944	12,545	12,269						
2021		12,960	12,560	12,290	13,080	12,680	12,400	12,840	12,460	12,190
2022		12,960	12,570	12,300	13,140	12,730	12,450	12,780	12,400	12,140
2023		12,960	12,560	12,290	13,190	12,770	12,490	12,730	12,350	12,080
2024		12,970	12,560	12,280	13,270	12,830	12,550	12,700	12,310	12,050
2025		13,020	12,590	12,320	13,400	12,940	12,650	12,700	12,300	12,030
2026		13,060	12,630	12,350	13,540	13,060	12,760	12,680	12,280	12,010
2027		13,130	12,680	12,400	13,700	13,180	12,880	12,680	12,270	12,000
2028		13,210	12,740	12,460	13,860	13,320	13,020	12,680	12,260	11,990
2029		13,340	12,860	12,570	14,050	13,480	13,170	12,690	12,270	12,000
2030		13,510	13,010	12,720	14,270	13,670	13,360	12,790	12,360	12,080
Compound Average Growth Rate 2021 – 2030		0.5%	0.4%	0.4%	1.0%	0.8%	0.8%	0.0%	-0.1%	-0.1%

Figure 4.9 shows the composition of historic winter MD and the medium growth forecast. A significant amount of potential load increase in the grid has been, and will continue to be, offset by energy efficiency. In the later forecast years, batteries discharging around the time of the network peak also act to moderate the impact of underlying demand on the grid maximum demand.

Sunset in NSW during the winter months is around 5:00 pm to 5:30 pm. Accordingly there is no offset in winter from rooftop PV generation as such generation is not available at the time of the winter maximum demand which occurs between 6:00 pm and 6:30 pm.

Figure 4.9: Composition of NSW region winter MD (actual and 50% POE medium forecast)



4.2.11 Minimum demand forecast

NSW minimum system demand has traditionally occurred overnight (in the early morning) on 25 or 26 December, as a result of low underlying demand at those times. This is changing as greater uptake of behind-the-meter rooftop PV generation causes a dip in network load during the daytime. In 2020, a minimum demand for the financial year of 5,496 MW occurred at 2 p.m. Eastern Standard Time on Christmas day. As more small-scale PV is installed, future daytime minimum demands are statistically most likely to occur in the shoulder period (month of October).

Forecasts for medium, high and low scenarios for minimum demand are shown in **Figure 4.10** and **Table 4.6**. The forecasts include the 10%, 50% and 90% POE levels for each scenario. The forecasts reflect statistical probabilities of daytime minimum demands occurring in the middle of the day due to increased uptake of rooftop PV (causing lower grid demand) and mild growth in average demand on the network.

Figure 4.10: NSW region as-generated minimum demand (MW) medium forecast

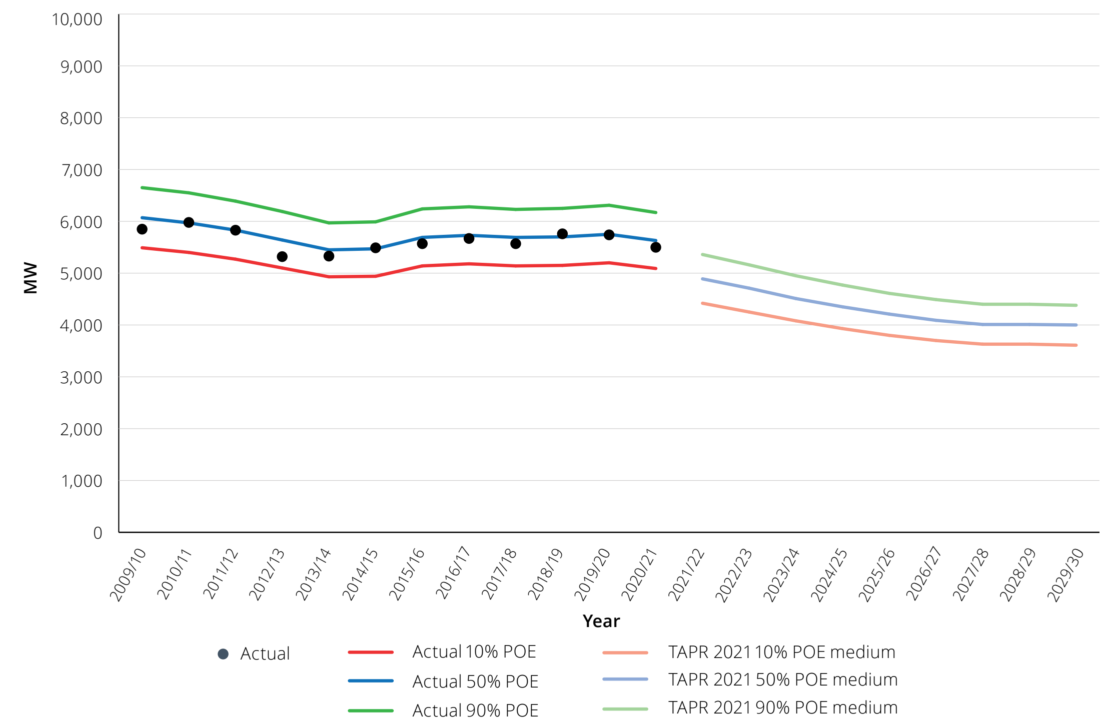


Table 4.6: NSW region as-generated minimum demand (MW) forecast

	Actual	Medium			High			Low		
		10% POE	50% POE	90% POE	10% POE	50% POE	90% POE	10% POE	50% POE	90% POE
2014/15	5,486	4,941	5,466	5,990						
2015/16	5,572	5,143	5,689	6,235						
2016/17	14,859	5,178	5,728	6,278						
2017/18	5,570	5,142	5,689	6,235						
2018/19	5,762	5,153	5,700	6,247						
2019/20	5,739	5,201	5,753	6,305						
2020/21	5,496	5,087	5,627	6,167						
2021/22		4,420	4,890	5,360	4,470	4,950	5,420	4,380	4,850	5,310
2022/23		4,250	4,710	5,160	4,310	4,770	5,230	4,220	4,670	5,120
2023/24		4,080	4,510	4,950	4,240	4,690	5,140	4,080	4,520	4,950
2024/25		3,930	4,350	4,770	4,190	4,630	5,080	3,950	4,370	4,790
2025/26		3,800	4,210	4,610	4,150	4,590	5,030	3,800	4,200	4,600
2026/27		3,700	4,090	4,490	4,130	4,570	5,010	3,650	4,040	4,430
2027/28		3,630	4,010	4,400	4,130	4,560	5,000	3,510	3,890	4,260
2028/29		3,630	4,010	4,400	4,130	4,570	5,010	3,420	3,780	4,140
2029/30		3,610	4,000	4,380	4,170	4,610	5,060	3,390	3,750	4,110
2030/31		3,620	4,000	4,390	4,200	4,650	5,090	3,350	3,710	4,070
Compound Average Growth Rate 2021/22 – 2030/31		-2.2%	-2.2%	-2.2%	-0.7%	-0.7%	-0.7%	-2.9%	-2.9%	-2.9%

4.3 Bulk supply point forecasts

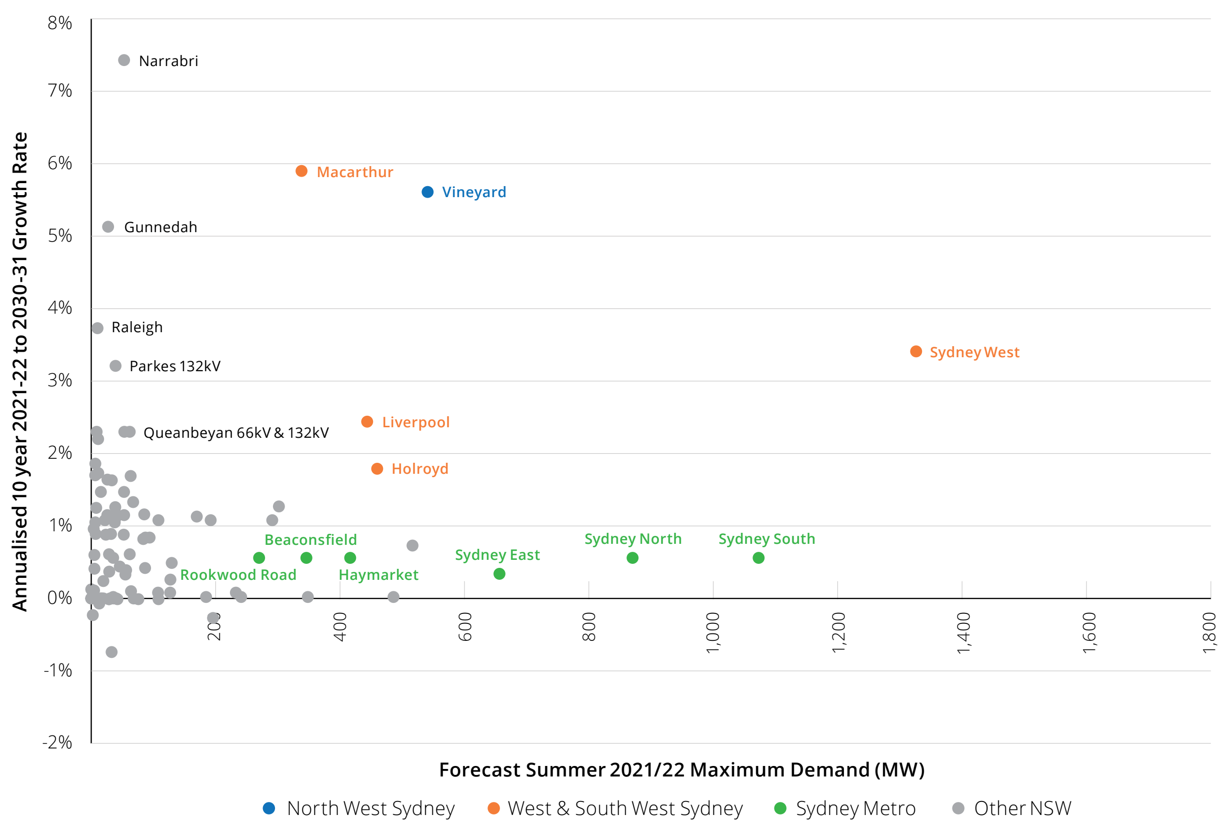
Generally, the load changes at BSPs are organic. Where there are spot loads[36], however they will be included in the relevant forecasts. The BSP forecasts incorporate the local knowledge of the relevant DNSPs and directly connected customers.

Macroeconomic data is generally not available at a BSP level. Consequently, it is generally not possible to develop macroeconomic models for individual BSPs and to produce forecasts for different economic scenarios. In practice, the BSP forecasts are produced in a variety of ways, reflecting the amount of data available and the nature of the loads.

Figure 4.11 shows the forecast growth rates for BSPs serving the respective DNSPs in summer, with annualised growth rates. The detailed year-on-year forecasts of summer and winter maximum demands at the individual BSP level are set out in **Appendix 2**. This data was provided by the relevant distributor (i.e. DNSPs) and directly connected customers to TransGrid in early 2021. The DNSP's methodologies for load forecasting should be referred in the respective DNSP's annual planning report.

The BSPs with the highest growth rates are those serving the following areas.

Figure 4.11: BSP summer forecast growth rates



West and South-West Sydney

This area is predominantly within the South West Sector Land Release and Broader Western Sydney Employment Area where a large number of residential lot releases are planned. Load increases are also expected due to the new Western Sydney Airport at Badgerys Creek. The Aerotropolis development in the vicinity of the Airport (Nancy-Bird Walton) is planned as a smart city and will include associated commercial, residential and light industrial/ancillary services growth in this region. Load increases would also occur from expansion and construction of existing and prospective data centres.

North-West Sydney

The development and operation of North West Rail infrastructure and associated activity in medium/high density residential, commercial & industrial areas will drive load growth in this area.

Sydney Inner Metropolitan area

This area continues to grow at a higher rate than the overall NSW region average. Real income and population growth is forecast to result in higher load growth in the long run. The NSW Government is delivering and planning a range of projects (electricity loads) in Sydney Inner Metropolitan area including transport infrastructure and a number of precinct or urban developments. Beaconsfield and Haymarket BSPs are two of our largest exit points which supply the Sydney Inner Metropolitan area.

36 Spot loads are step (one-off) increases in load for a BSP due to new commercial/housing developments or large industrial customer connections. There could be spot load decreases in cases where there are withdrawals of large load customers from the grid.

Other NSW

Other NSW consists of areas in Central West, Northern and Southern parts of the state. The new spot loads in Central West area primarily relate to the developments in and around the upcoming Parkes Special Activation Precinct (SAP). The Parkes SAP is expected to create new jobs in the freight and logistics industry, optimise opportunities in the agricultural industry and bring regional suppliers closer to their customers, allowing products from the Central West to be delivered across Australia and around the world faster. While Northern NSW is expected to see the development of a major gas project, Southern NSW including areas in the Evoenergy network will see enhanced load growth from mining/industrial developments and new data centres.

4.3.1 TransGrid 2021 NSW region forecast vs aggregate DNSP BSP forecast

Historical comparisons have shown that aggregate BSP forecasts obtained from DNSPs are on average higher than NSW Region forecasts. This is because DNSP forecasts are not generally based on econometric modelling[37] and include localised spot loads. Also most DNSP forecasts have little or no adjustments for energy efficiency and rooftop PV unlike NSW Region forecasts. Therefore, the comparison of bottom up BSP forecasts obtained from DNSPs is with TransGrid's top down NSW Region high forecast, as the high scenario is closer to the aggregate DNSP forecast due to the above-mentioned reasons.

Unlike TransGrid's NSW region forecast, none of the BSP loads, by definition, include transmission network losses and power station auxiliary load. Despite this difference, the individual BSP forecasts for each season can be aggregated to provide a useful comparison with the overall NSW region demand forecast. In order to achieve this, we consider the following:

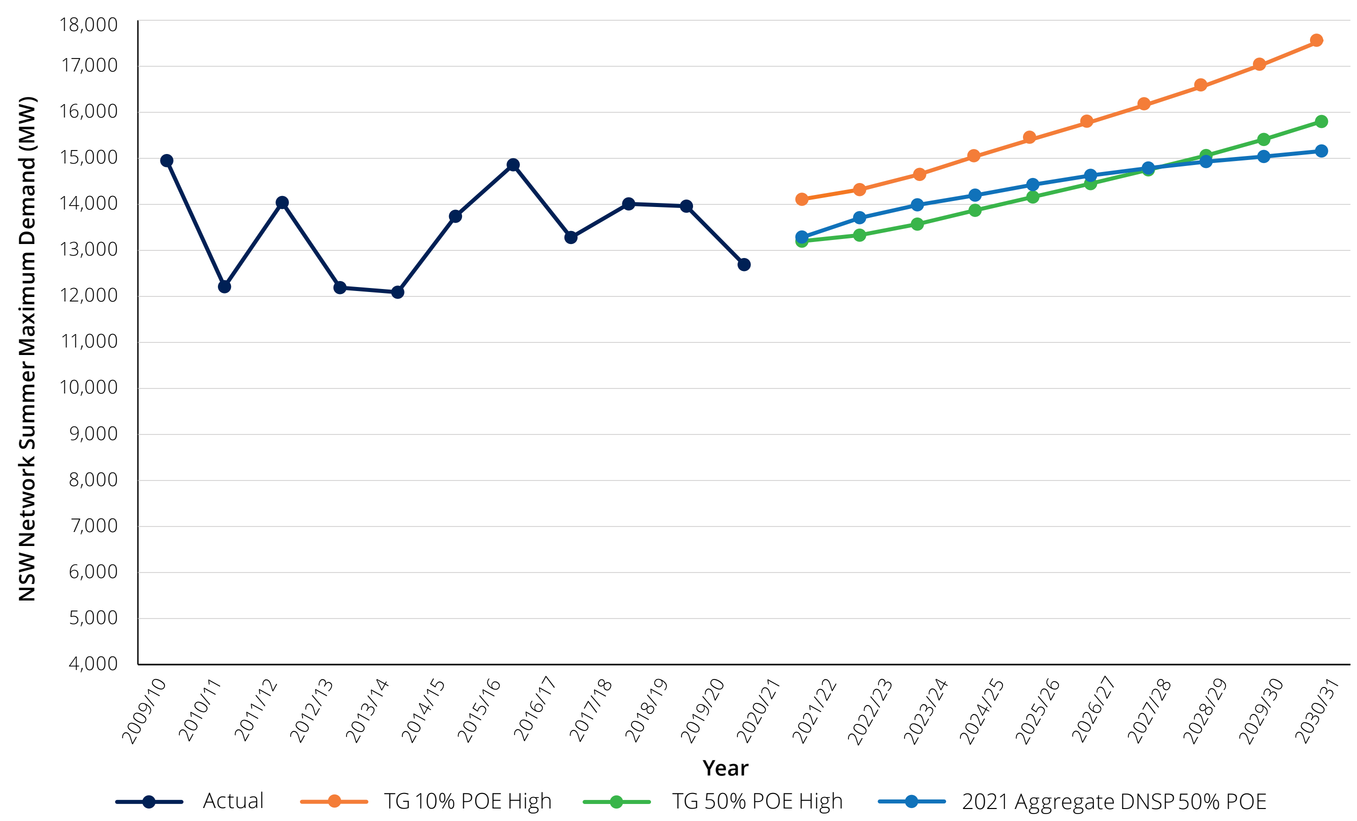
- Diversity of load or timing of maximum demand;
- Transmission network losses; and
- Power station auxiliary load.

TransGrid accounts the above mentioned limitations by:

- Using 50% POE forecasts where they are available, and where they are not available, by assuming that individual BSP projections are likely to have been based on enough historical data to converge towards an approximate 50% POE forecast;
- 'Diversifying' individual BSP forecasts to allow for the time diversity observed between historical local seasonal maximum demand and NSW maximum demand;
- Adding forecast aggregate directly connected industrial loads not included in the BSP forecasts; and
- Incorporating transmission network losses and power station auxiliary loads, derived from recent historical observations, to express the forecasts in the same 'as-generated' basis for comparison with TransGrid's 2021 NSW forecast.

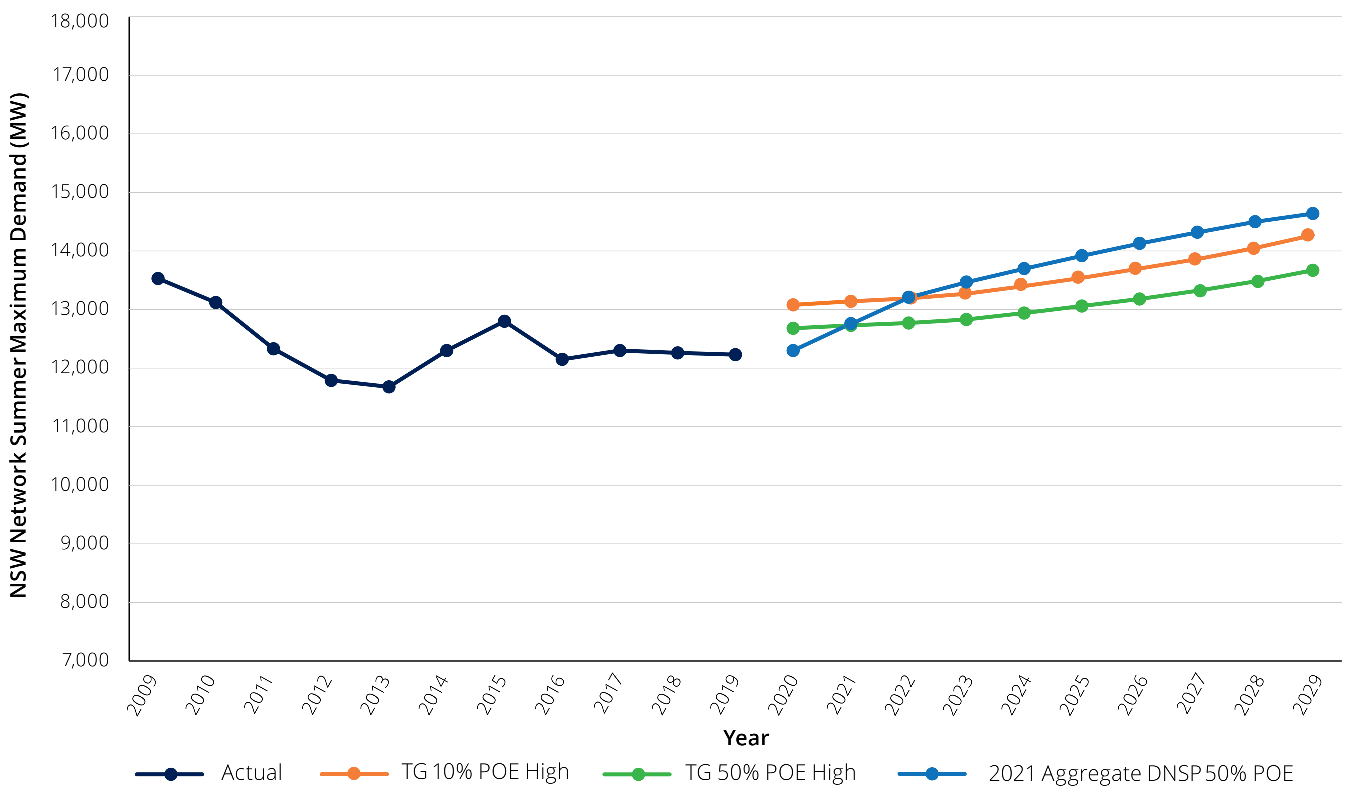
Figure 4.12 and **Figure 4.13** show aggregate BSP summer and winter maximum demand forecasts compared with TransGrid's 10% and 50% POE high NSW region summer and winter maximum demand forecasts respectively for NSW and ACT region.

Figure 4.12: TransGrid's top down forecast vs aggregate BSPs forecast for summer maximum demand



37 Econometric data like GSP and HDI are not generally available at a BSP level. Hence DNSP forecasting methodologies tend to rely on time series forecasting with upward adjustments for future localised spot load developments.

Figure 4.13: TransGrid's top down forecast vs aggregate BSPs forecast for winter maximum demand



The charts above show that while aggregate DNSP projection for summer lie within TransGrid's 50% and 10%POE bands for summer, aggregate BSP forecast for winter is slightly above the TransGrid's top down winter forecasts. The differences between the forecasts are understandable as the two sets of forecasts (DNSP aggregate BSP vs TransGrid top down) are produced on different basis.

Although the comparison between TransGrid's 2021 top down forecasts and the DNSPs' aggregate of BSP forecasts do not indicate which forecast is more accurate, they, nonetheless, allow for a high-level comparison to be made.

4.4 TransGrid's 2021 forecast vs AEMO's 2020 ESOO forecasts for NSW region

The most recent update of AEMO's top down forecasts for the NSW region was published in August 2020 as an update to the 2020 Electricity Statement of Opportunities (ESOO). This section compares TransGrid's 2021 top down maximum demand forecast and AEMO's latest maximum demand forecast update for the NSW region.

Both demand forecasts are presented on a 'native as-generated' basis. The details of AEMO's demand forecast is provided on the AEMO website.[38]

In order to compare the TransGrid and AEMO summer and winter maximum demand forecasts, TransGrid combined AEMO's 'native sent out' neutral 50% POE forecast and AEMO's 'auxiliary load' neutral 50% POE forecast. This summated AEMO forecast is compared to TransGrid's 'as-generated' medium 50% POE forecast and is shown in the following figures.

Figure 4.14 and **Figure 4.15** show a comparison between TransGrid's 2021 summer and winter maximum demand medium scenario forecasts and AEMO's most recent central scenario (summer and winter) maximum demand forecasts in its 2020 ESOO. Both forecasts are expressed on a "native as generated basis" and hence can be directly compared.

38 https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/2020-electricity-statement-of-opportunities.pdf?la=en

Figure 4.14: TransGrid's 2021 vs AEMO's ESOO 2020 summer maximum demand forecast for NSW region

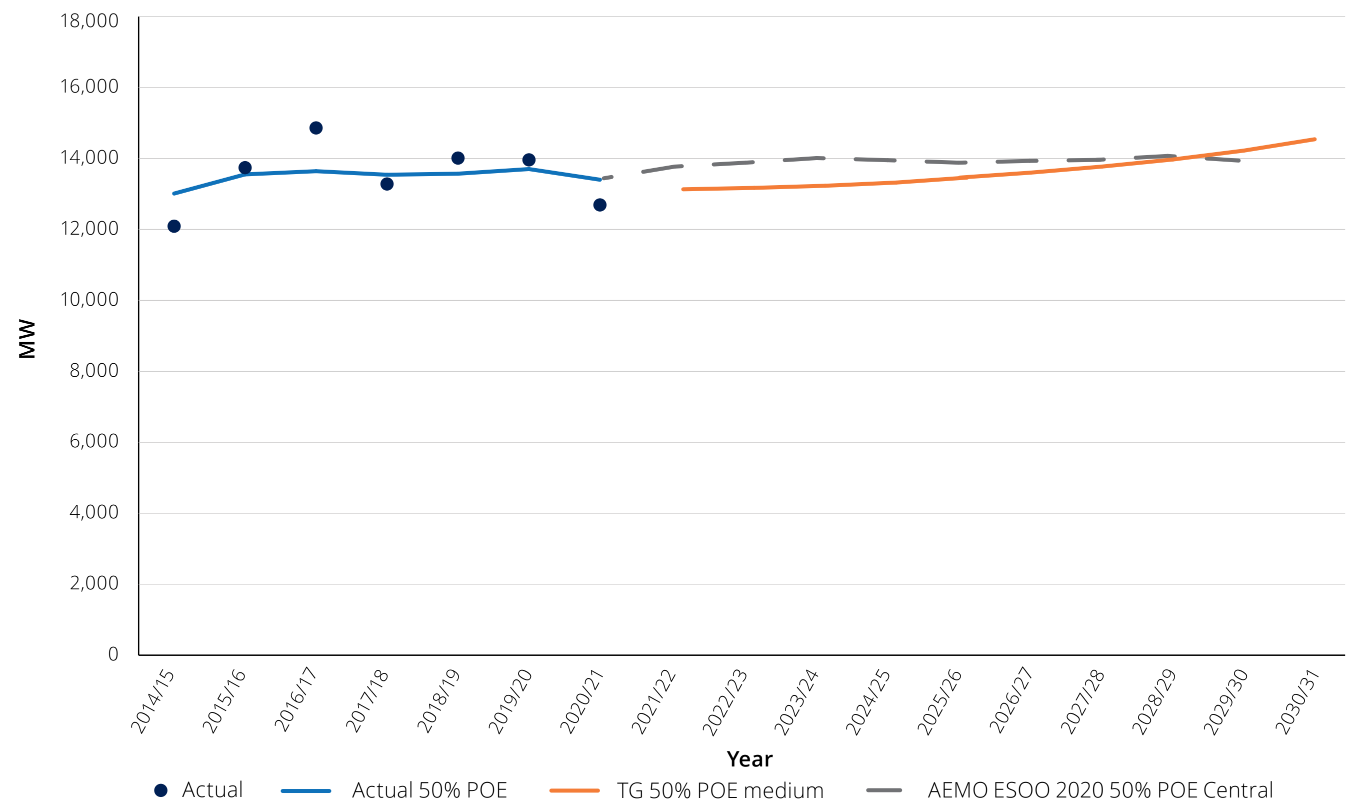
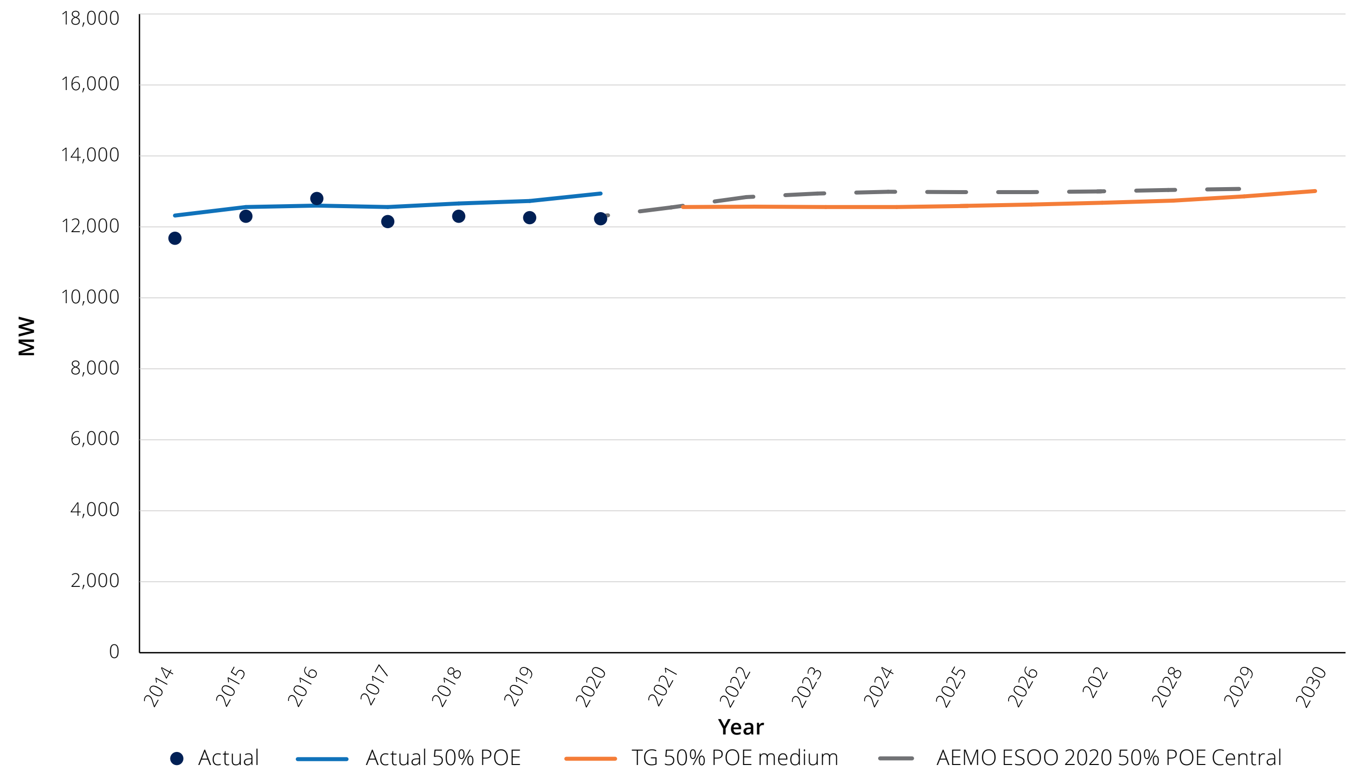


Figure 4.15: TransGrid's 2021 vs AEMO's ESOO 2020 winter demand forecast for NSW region



4.5 Joint planning

4.5.1 Co-ordination and working groups

TransGrid regularly undertakes joint planning with AEMO and Jurisdictional Planning Bodies from across the NEM. There are a number of working groups and reference groups in which TransGrid participates:

- Executive Joint Planning Committee;
- Joint Planning Committee;
- Regulatory Working Group;
- Regular coordination meetings; and
- NEM Planning & Design Working Group of the Energy Networks Association.

Executive Joint Planning Committee

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

- Develop a framework for the ISP;
- Continuously improve current network planning practices; and
- Coordinate on energy security across the NEM.

The Executive Joint Planning Committee directs and coordinates the activities of the Forecasting Reference Group, and the Regulatory Working Group as outlined below. These activities ensure effective consultation and coordination between Jurisdictional Planning Bodies, Transmission System Operators and AEMO on a broad spectrum of perspectives on network planning, forecasting, market modelling, and market regulatory matters in order to deal with the challenges of a rapidly changing energy industry.

Joint Planning Committee

The Joint Planning Committee (JPC) is a working committee supporting the Executive Joint Planning Committee (EJPC) in achieving effective collaboration, consultation and coordination between Jurisdictional Planning Bodies (JPB), Transmission System Operators and AEMO on electricity transmission network planning issues.

Forecasting Reference Group

The Forecasting Reference Group (FRG) is a monthly forum with AEMO and industry 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.

Regulatory Working Group

The Regulatory Working Group (RWG) is a working group to support the EJPC in achieving 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.

Power system modelling reference group

This is a technical expert reference group which focuses on power system modelling and analysis techniques to ensure an accurate power system model is maintained for power system planning and operational analysis, establishing procedures and methodologies for power system analysis, plant commissioning and model validation.

Regular joint planning meetings

For the purpose of effective network planning, TransGrid conducts regular joint planning meetings with:

- AEMO National Planning;
- AEMO Victoria Planning;
- ElectraNet;
- Powerlink;
- Ausgrid;
- Endeavour Energy;
- Essential Energy; and
- Evoenergy.

4.5.2 Joint Planning Projects

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

- 2022 ISP Input and Assumptions;
- South Australian Energy Transformation and EnergyConnect;
- Expanding NSW to Queensland Transmission Transfer Capacity (QNI Upgrade);
- Victoria to New South Wales Interconnector Upgrade (VNI Upgrade); and
- Victoria to NSW Interconnector West (VNI West)
- Details of these projects are provided in **Chapter 2**

4.6 Service standards

NSW Electricity Transmission Reliability and Performance Standard

The NSW Electricity Transmission Reliability and Performance Standard 2017 is administered by IPART. This Standard specifies two reliability criteria for each BSP:

- The required level of network redundancy for each BSP or group of BSPs that function as a cohort; and
- An allowance of Minutes of Expected Unserved Energy, which is the maximum amount of energy at risk of being not supplied in a given year expressed as minutes at the average load on the BSP.

The Standard is a planning, rather than a performance standard. This means the network needs to be planned to meet the standards over the life-cycle of the assets on average, rather than be met in every year.

Network investment may be required to ensure compliance with the Standard. The Standard however, also provides flexibility to promote the most efficient network or non-network solution to meet the Minutes of Expected Unserved Energy allowance. This may include changes to the transmission network, the distribution network, network support arrangements (including the use of Demand Management options), existing backup supply arrangements, or a combination of these.

TransGrid's annual compliance report for 2020 found all BSPs are compliant with reliability standard.

ACT reliability standard

TransGrid is subject to the Electricity Transmission Supply Code July 2016 under the transmission licence that TransGrid holds in the ACT. The Code includes the requirement for the provision of two or more geographically separate points of supply at 132 kV or above. It also requires that there be a continuous electricity supply at maximum demand to the ACT network at all times, including following a single credible contingency event.

The Canberra, Stockdill and Williamsdale Substations currently supply the ACT load. The construction of Stockdill 330/132 kV Substation has separated Williamsdale from Canberra and achieved the Code requirement for two fully independent supply points.

4.7 Alignment with ESOO and ISP

TransGrid observes that the reliability after the Liddell Power Station retires has improved since 2020 TAPR, as a result of the committed augmentation of the Queensland to New South Wales Interconnector (QNI) in 2022-23, Victoria to New South Wales Interconnector minor upgrade in 2022-23 and the local renewable generation. It is forecasted that the reliability standard is not to be exceeded until 2029-30. This is consistent with AEMO's 2020 Electricity Statement of Opportunities.[39]

Loss of an additional major power station in NSW after the retirement of Liddell Power Station could lead to a shortfall in supply, unless sufficient additional firming capability is developed in time.

The plans set out in this report aligns with 2020 Integrated System Plan.

4.8 Changes from TAPR 2020

Updates in this chapter and referenced Appendices, since TAPR 2020, includes:

- TransGrid has updated its forecasts for NSW energy consumption and maximum demands to provide a detailed outlook for electricity consumption and maximum demand for the region as a whole;
- The method of preparation of the TransGrid forecast is explained in **Appendix 1**: including a description of models, model evaluation, input variables and scenarios, other assumptions and independent advice; and
- A comparison of annual energy consumption and maximum demand between TransGrid's 2021 forecast and AEMO's 2020 ESOO forecast has been added.

These changes are consistent with the requirements of NER Clause 5.12.2(c)(1), (6A), (9), (10) and (12).

39 The AEMO 2020 Electricity Statement of Opportunities, August 2020

Chapter 5
Assessment of power system security

- There is a projected shortfall in generation to meet peak demand as coal-fired generation retires
- The shortfall can be met by new generation, greater interconnection, storage and demand management
- We expect shortfalls in system strength following the retirements of Liddell, Vales Point and Eraring Power Stations or if coal-fired power stations move to more flexible operation
- We expect a shortfall in inertia following the retirements of Liddell, Vales Point Power Stations or if coal-fired power stations move to more flexible operation.

5.1 Assessment of power security

The transmission network provides the platform to transport energy from large-scale generation to major load centres. It also provides power system stability by sharing ancillary services provided by generators and some network assets.

TransGrid has undertaken an assessment of power system security against each of the criteria that contribute to the stability of the power system. The criteria are shown in **Table 5.1**.

Table 5.1: Key considerations when developing the transmission network

Criteria	Description
Maximum demand (or peak demand)	Demand is the amount of electricity being used at an instant in time. Maximum demand is the highest amount of electricity that has been used (or is expected to be used) at any instant in a period of time.
Minimum demand	Minimum demand is the lowest amount of electricity that is used at any instant. Low minimum demand can present challenges to the stability of the power system.
Energy	The total amount of electricity used over a period of time.
Voltage control	The ability to maintain voltages throughout the power system within stable and safe limits.
System strength	The ability of the power system to temporarily provide high energy to manage disturbances while maintaining voltage control. System strength is provided by synchronous rotating generators. Inverter-based generators such as wind and solar generators require system strength to operate correctly but do not produce it.
Frequency control	The ability to maintain the frequency of the power system within stable limits. Traditional frequency control acts quickly for small changes in frequency under normal conditions, but slowly for large changes in frequency during disturbances. Therefore, it is complemented by inertia to ensure the power system can “ride through” disturbances without significant frequency variation while it responds. Fast frequency response (FFR) is a newer approach enabled by high speed power electronics. Battery storage devices and solar generators use these electronics in their inverters. FFR has the potential to act quickly during disturbances.
Inertia	The ability of the power system to “ride through” disturbances without significant frequency variation. Inertia (shorthand for “synchronous inertia”) measures the physical capability of synchronous rotating generators to continue without slowing down significantly during a disturbance. Unlike synchronous generators, wind generators do not always turn at the same speed as the power system frequency. Therefore, they connect to the power system using power electronics that converts either all of their output to the power system frequency, or a portion of their output that is then superimposed on the remaining portion of the output that comes directly from the wind turbines. Wind generators of the latter type are known as “type 3” generators. These generators can provide “synthetic inertia” using the inertia present in the wind turbines. This has slightly different characteristics to synchronous inertia.
Reserve	Extra generation that is readily available by increasing the output of generators already generating in the power system. The power system is normally operated with enough reserve to cover the loss of the largest generator unit.
Power system data communications	High speed data communications to provide visibility, monitoring and control of the power system. This includes dispatching generation and operating networks.

Maximum demand and energy

There is a projected shortfall in generation to meet maximum demand following the expected retirement of Liddell Power Station in 2022-23. A shortfall in generation to meet demand will result in unserved energy.

When the shortfall is limited to a small number of high-demand days, the unserved energy can be small. As the level of shortfall increases, however, the unserved energy increases significantly.

The shortfall can be met by additional new generation, greater interconnection, storage and demand management.

This is being managed by the connection of new generation to the network and projects to increase network capacity, discussed in **Chapter 2**.

Voltage control

Voltage control is provided by generators and network assets such as transformer tap changers, capacitor banks, reactors and Static VAr Compensators (SVCs).

There is sufficient voltage control capability in general in the NSW transmission network over the next 10 years. Additional voltage control issues are however emerging in the south west NSW network and North West NSW due to high levels of renewable generation in the area.

At times of high renewable generation near south west NSW Network and North Western NSW Darlington Point, under-voltages can occur due to the trip of the Darlington Point to Wagga 330 kV transmission line.

A new voltage stability limit has been introduced in generation dispatch to cater for this contingency.

At times of high renewable generation near Moree, over-voltages can occur due to minimum demand during the day.

There are opportunities to make small increases to interconnector export capacity to Queensland (Qld) through the installation of additional network assets for voltage control. The QNI Upgrade project to install capacitor banks and SVCs in Northern NSW to increase QNI import and export capacity is now included as an ongoing project in **Section 2.1.1**.

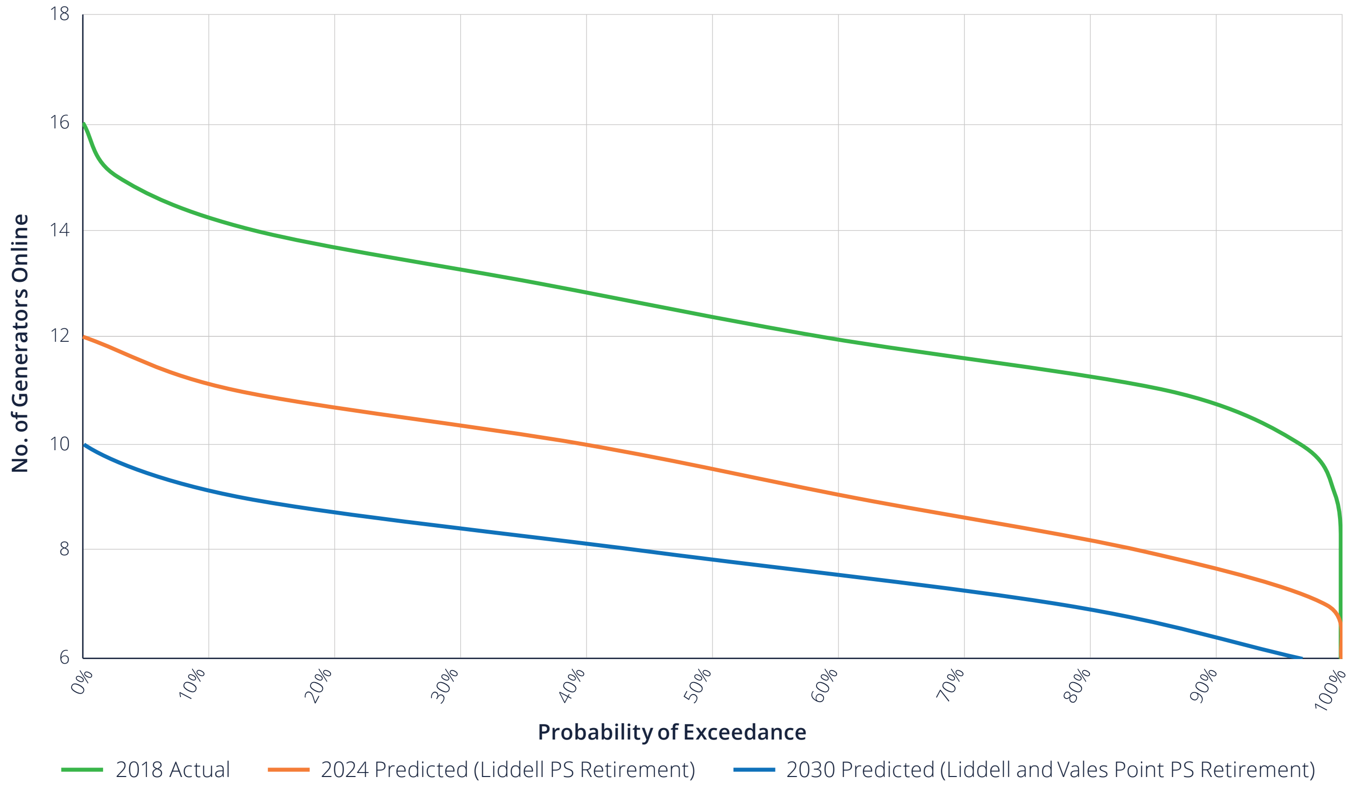
System strength

Presently, coal-fired synchronous generators provide the majority of system strength in the NSW transmission network. System strength can also be provided by other synchronous rotating generators and synchronous condensers. New technologies, such as grid forming inverters are also expected to provide system strength; however, these are still in development stages.

We have reviewed the adequacy of system strength in the NSW transmission network for minimum synchronous generation conditions. System strength was analysed based on the system's ability to maintain the required minimum three-phase fault levels (specified by AEMO) and the availability of adequate synchronous generation in the network with forecasted generator retirements. A minimum of seven coal-fired synchronous generator units is adequate to meet the minimum fault levels required at the fault level nodes as per AEMO System Strength Requirements[40].

Figure 5.1 shows the cumulative probability of the number of coal-fired synchronous generation online with the removal of generator units (as a result of retirements of coal-fired generation units or them moving to flexible operation). This assessment is based on the historical number of coal-fired synchronous generators online in 2018.

Figure 5.1: Cumulative probability of Coal Generator Availability with generator retirements



40 AEMO 2020 System Strength and Inertia Report, December 2020

Table 5.2 shows the emergence of system strength shortfalls at NSW fault level nodes with the retirement of Liddell and Vales Point, Eraring and Bayswater Power Stations.

Table 5.2: Fault levels with minimum generation profile

330 kV Fault Level Node	AEMO expected minimum fault level[41]		Fault Level with minimum generation profile (MVA)					
			Liddell + Vales Point Retired		Liddell + Vales Point + Eraring Retired		Liddell + Vales Point + Eraring + Bayswater Retired	
Scenario	N	N - 1	N	N - 1	N	N - 1	N	N - 1
Armidale	3300	2800	3550	2920	3550	2920	2940	2590
Darlington Pt	1500	600	1930	750	1910	750	1790	730
Newcastle	8150	7100	8290	7440	6300	5320	3870	3590
Sydney West	8450	8050	8510	8160	7130	6990	4390	4350
Wellington	2900	1800	3300	2080	3250	2050	2640	1850

Table 5.3 shows the system strength shortfalls at NSW fault level nodes with the retirement of Liddell, Vales Point, Eraring and Bayswater Power Stations.

These shortfalls are based on the AEMO minimum fault levels as per 2020 System Strength and Inertia Report document published in December 2020.

Table 5.3: Indicative Fault Level Shortfall with generation retirement

330 kV Fault Level Node	AEMO expected minimum fault level[41]		Indicative Fault Level Shortfall (MVA)					
			Liddell + Vales Point Retired		Liddell + Vales Point + Eraring Retired		Liddell + Vales Point + Eraring + Bayswater Retired	
Scenario	N	N - 1	N	N - 1	N	N - 1	N	N - 1
Armidale	3300	2800	N/A	N/A	N/A	N/A	360	210
Darlington Pt	1500	600	N/A	N/A	N/A	N/A	N/A	N/A
Newcastle	8150	7100	N/A	N/A	1850	1780	4280	3510
Sydney West	8450	8050	N/A	N/A	1320	1060	4060	3700
Wellington	2900	1800	N/A	N/A	N/A	N/A	260	N/A

The review shows that:

- There is sufficient system strength presently in most parts of the NSW transmission network.
- With the retirement of Liddell Power Station (refer orange curve in **Figure 5.1**), system strength is expected to be at satisfactory levels at all times (i.e. greater than 7 coal-fired synchronous generator units online).
- With the Liddell and Vales Point Power Stations retirements (refer blue curve in **Figure 5.1**), system strength is expected to be reduced to unsatisfactory levels for about 3% of the time (i.e. less than 7 coal-fired synchronous generator units online).
- System strength shortfalls are expected to be much more pronounced following the additional retirement of Eraring Power Station. There will be system strength shortfalls for 100% of the time at this time (i.e. less than 7 coal-fired synchronous generator units).

The system strength shortfalls can occur earlier than expected if coal-fired power stations retire early or move to flexible operation where they can go offline during times of light load or low price.

System strength shortfalls can be addressed by careful management of synchronous generator outages (i.e. limiting concurrent generator planned outages), contracting additional synchronous generator services, converting retiring synchronous generators to operate as synchronous condensers, introduction of synchronous condensers, and using new technologies such as grid forming batteries[42].

The assessments undertaken reveal that the potential for interconnectors to improve system strength is limited. Any benefits to system strength from interconnectors may only be regional and are not likely to improve system strength across the network.

Wind, solar and other inverter-based generators require system strength to operate correctly. As the penetration of inverter-based generators increases, there will be a need to procure additional network assets or schedule existing synchronous generators to provide the necessary system strength services at all times.

41 As per AEMO System Strength and Inertia Report published in December 2020.
42 TransGrid will further investigate this as part of a 50 MW grid battery project in Western Sydney (referred in Section 2.3.1)

Frequency control

Frequency control is provided across the NEM through inertia, Fast Frequency Response (FFR) and Frequency Control Ancillary Services (FCAS). There is sufficient frequency control capability in the NEM over the next 10 years, provided there is adequate inertia installed in the NEM.

FFR has the potential to act quickly during disturbances and is a partial substitute for synchronous inertia. A project to install a large-scale battery to understand its performance has been included in **Section 2.3.1**. This will enable its application in practice to be understood and validated in system stability models.

Inertia

We have reviewed the adequacy of inertia in NSW to limit the rate of change of frequency (RoCoF) and frequency deviation following a disturbance. We also modelled the NSW system frequency response for a single and multiple generator trip[43] events. **Table 5.4** summarises the Initial Rate of Change of Frequency (RoCoF) and Minimum Frequency for a single generator and double generator trip event with retirement of coal-fired synchronous generators.

Table 5.4: Frequency response for single and multiple generator trip events with NSW generation retirement

Power Stations Decommissioned	Estimated Remaining Minimum System Inertia (MWs)	Initial RoCoF (Hz/s)	Largest Generator Trip Minimum Frequency (Hz)	Double Generator Trip[43,45] Minimum Frequency (Hz)
None	23,000	-0.88	49.33	49.01
Liddell	18,100	-1.15	49.24	48.89
Liddell and Vales Point	15,600	-1.37	49.17	48.80
Liddell, Vales Point and Eraring	10,600	-2.15	48.97	N/A - Unstable
Liddell, Vales Point, Eraring and Bayswater	4,900[44]	N/A - Unstable	N/A - Unstable	N/A – Unstable

The information in **Table 5.4** (above) reveals that the NSW system is unlikely to withstand a multiple generator trip event following the retirement of Liddell, Vales Point and Eraring Power Stations. Therefore, the actual requirements for the power system are likely to be greater than the levels considered and presently mandated. We need to consider multiple generator trips because such events happen on the power system[45] and inertia is essential for the stability and continuous operation of the power system. We have therefore used 15,000 MWs as the level of inertia to assess and plan to meet this, being the level that is secure for the trip of two generators.

Inertia and its contribution to frequency control in NSW were evaluated according to the forecasted changes to typical and minimum inertia levels with scheduled synchronous generator retirements.

Figure 5.2 shows the reduction in inertia in NSW as the coal fired generators retire. The timeline for this analysis is based on published retirement dates.

Figure 5.2: System inertia (typical) reduction due to synchronous generator retirement

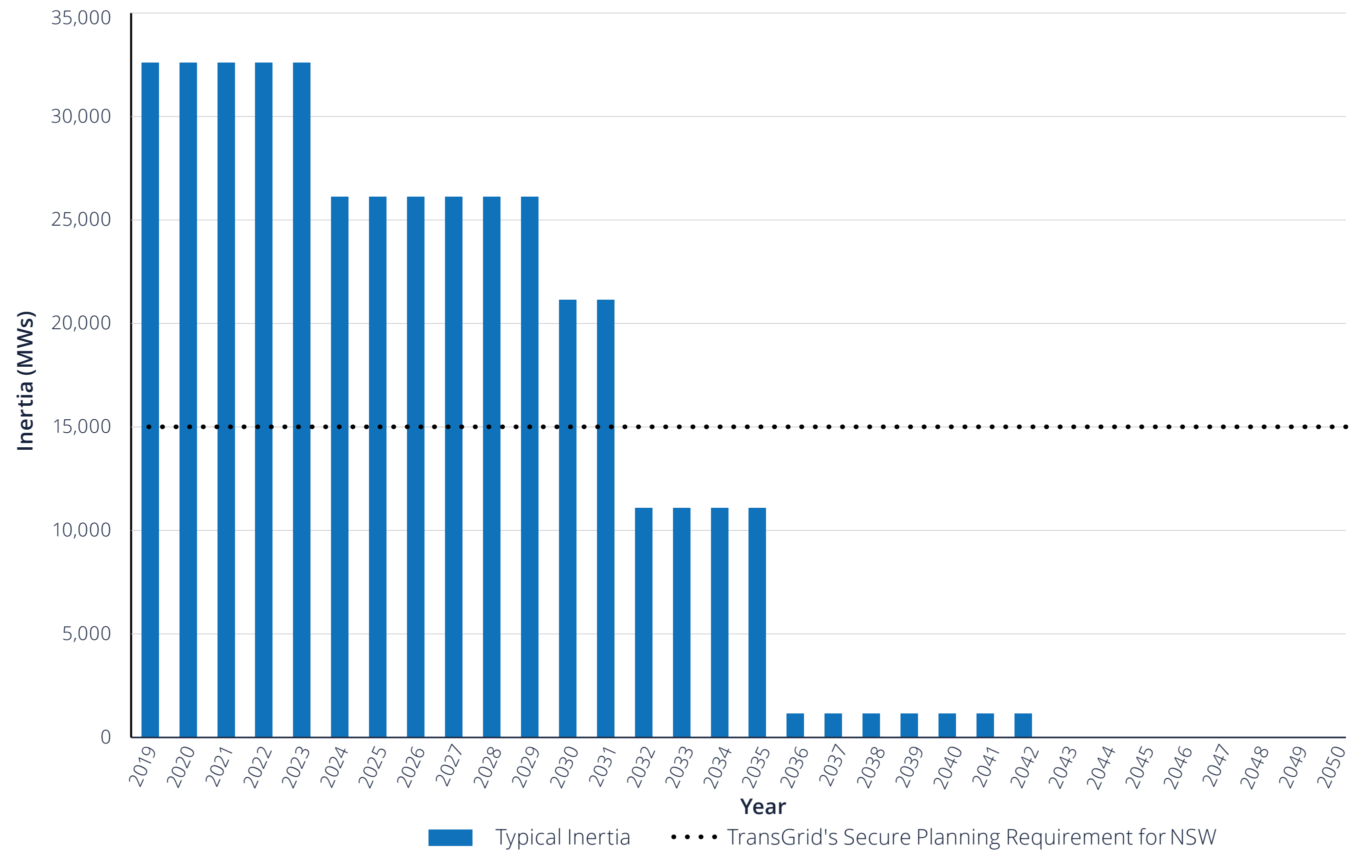
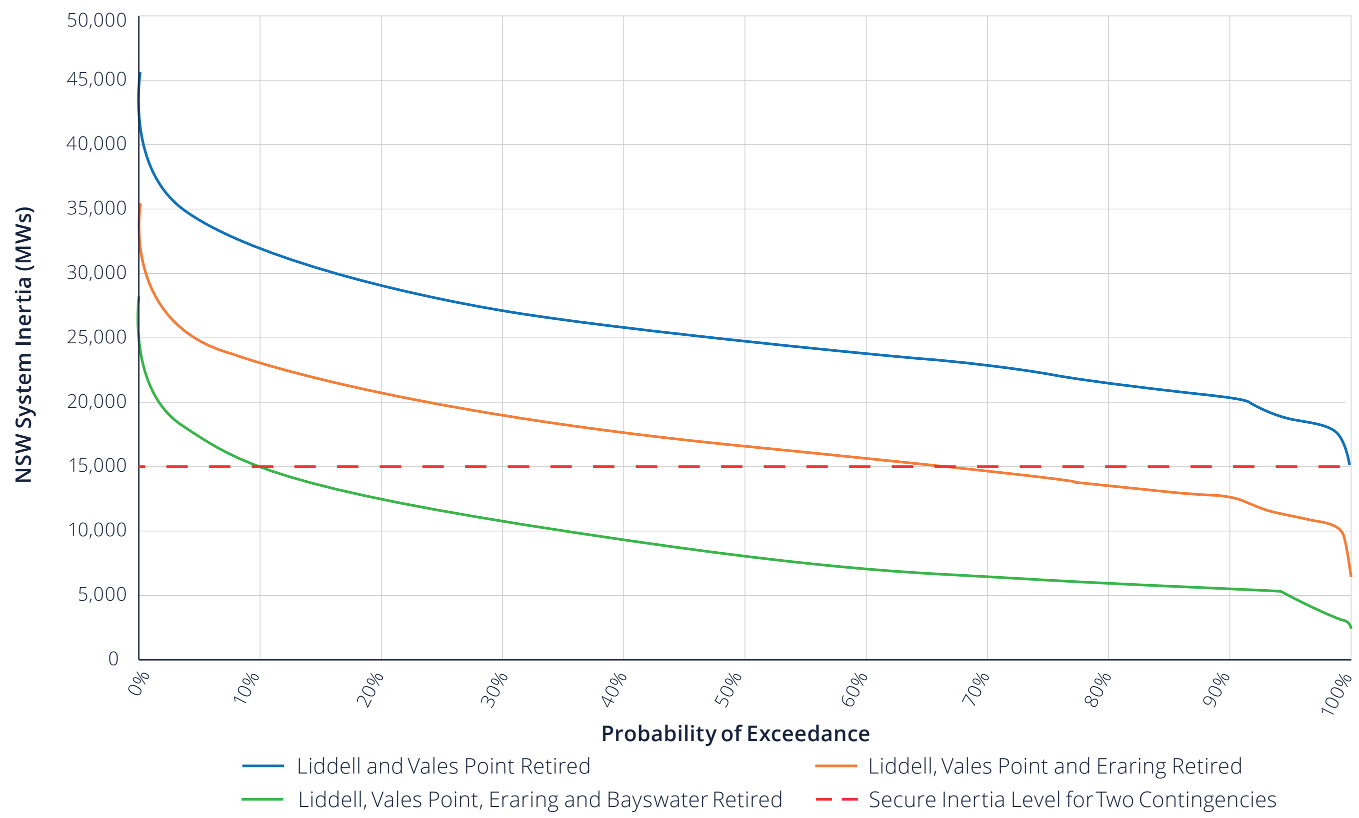


Figure 5.3 shows the cumulative probability of available inertia in NSW with the removal of generator units (as a result of retirements of coal-fired generation units or them moving to flexible operation). This assessment is based on the historical number of coal-fired synchronous generators online in 2018.

Figure 5.3: Cumulative probability of NSW system inertia with generator retirements



43 For example, the trip of multiple generators at Bayswater on 2 July 2009.
44 This assumes that the two remaining Mt Piper units are in service.
45 The 2 generator events were modelled 600ms apart based on 2009 Bayswater incident generator trip sequence

Table 5.5 shows the inertia shortfalls as the coal fired units retire to meet the AEMO's minimum inertia requirement of 10,000 MWs (as published in 2020) and the double contingency secure planning inertia level of 15,000 MWs, respectively.

Table 5.5: Inertia shortfalls in NSW with generation retirement

Scenario	Inertia Shortfall to meet AEMO's Minimum Inertia requirement of 10,000 MWs[46] (MWs)	Inertia Shortfall to meet the double contingency secure planning level of 15,000 MWs (MWs)
Liddell Power Station retired	N/A	N/A
Liddell and Vales Point Power Stations retired	N/A	N/A
Liddell, Vales Point and Eraring Power Stations retired	3,300	8,300
Liddell, Vales Point, Eraring and Bayswater retired	7,400	12,400

The review shows:

- The expected inertia level in NSW is unlikely to meet the double contingency secure planning inertia level of 15,000 MWs following the retirements of Liddell, Vales Point and Eraring Power Stations for about 32% of the time during a year (refer orange curve in **Figure 5.3**), and for about 90% of the time during a year following the retirements of Liddell, Vales Point, Eraring and Bayswater Power Stations (refer green curve in **Figure 5.3**).
- Inertia shortfalls are expected to be much more pronounced following the retirement of Liddell, Vales Point and Eraring Power Stations. Up to 3,300 MWs of additional synchronous inertia will be required to meet AEMO's minimum inertia requirement of 10,000 MWs. Additional frequency control measures equivalent up to 8,300 MWs of inertia will be required to meet the double contingency planning inertia requirement (refer **Table 5.5**).

Inertia shortfalls can occur earlier than expected if coal-fired power stations retire early or move to flexible operation where they can go offline during times of light load or low price. These are likely to result in a lower availability of adequate inertia in the network requiring careful management of synchronous generator outages, contracting non-base load synchronous machines (generators), introduction of synchronous condensers with flywheels, conversion of retiring generators to synchronous condensers and 'synthetic inertia' (subject to successful trials).

The emergence of Fast Frequency Response (FFR) devices such as Battery Energy Storage Systems (BESS) also have the potential to support frequency control in the future, in particular in satisfying the Secure level of inertia requirement. However, the effectiveness of FFR devices in replacing reduction in inertia is dependent on the speed of response of FFR devices and the associated protection and control schemes as shown in **Figure 5.4**. This graph shows the BESS requirement to match the present NSW system frequency response for a large generator trip with increase in synchronous generator inertia retirements. Similarly, **Figure 5.5** indicates the battery requirements to securely manage frequency control in the event of a double generator trip. These analyses are based on assumptions made as to the potential speed of response of the BESS from the frequency event occurring, rather than BESS supplier reported speed from detecting the event.

Figure 5.4: BESS sizing requirements due to inertia retirements based on speed of response

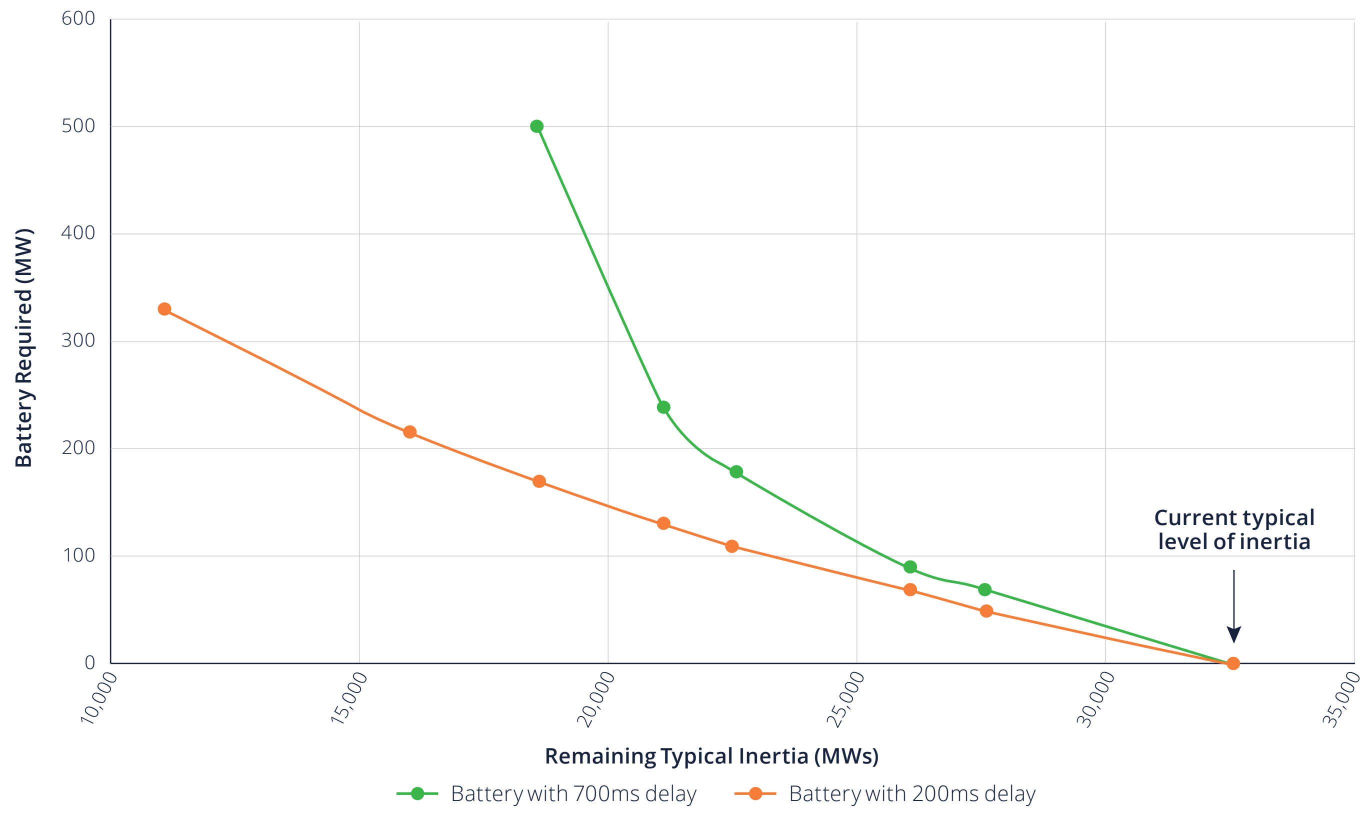
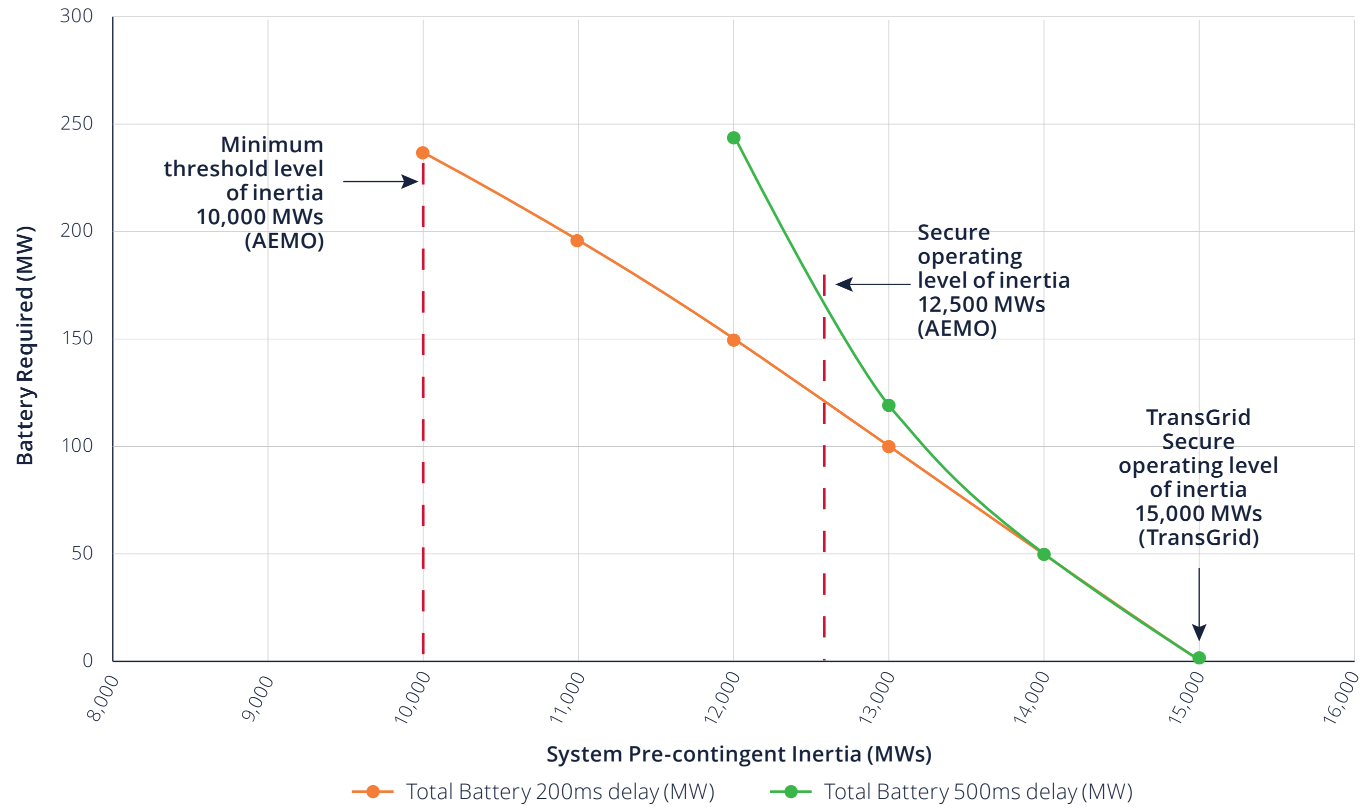


Figure 5.5: BESS sizing requirements for double generator contingency based on speed of response



46 As per AEMO Inertia Requirements published in December 2020, minimum and secure inertia requirements are 10,000 MWs and 12,500 MWs respectively.

The analysis reveals:

- The higher the speed of the BESS, the quicker it is able to respond to arrest the frequency deviation, and the smaller the overall battery requirement to achieve the same network stability
- The ability of the BESS to satisfy any shortfalls in secure planning requirement depends on the delay in response of the system. A delay less than 200ms would allow meeting full range of secure planning requirement above the minimum inertia requirement of 10,000 MWs to be met by BESS. However, if the delay is greater than 200ms, additional synchronous inertia will be required to meet the double contingency planning level of 15,000 MWs.

Reserve

In NSW, the power system is generally operated with a reserve level of 700 MW.

There will be a lack of reserve when there is a shortfall of generation to meet demand, or when the available generation is less than 700 MW above demand.

There is a projected shortfall in reserve under certain conditions over the period of this report. The shortfall can be met by additional new generation, greater interconnection, storage and demand management.

Power system data communications

High speed data communications contributes to power system security by providing visibility, monitoring and control of the power system.

TransGrid is also working to develop least-cost communications solutions to areas of NSW with the best renewable resources, as new generation connects and large-scale energy zones are established.

Appendix 1

TransGrid 2021 NSW region load forecasting methodology

This appendix describes the forecasting methodology including the sources of input information, applied assumptions, load forecast components, model schema, weather correction steps and input data variables.

A1.1 Overall schema

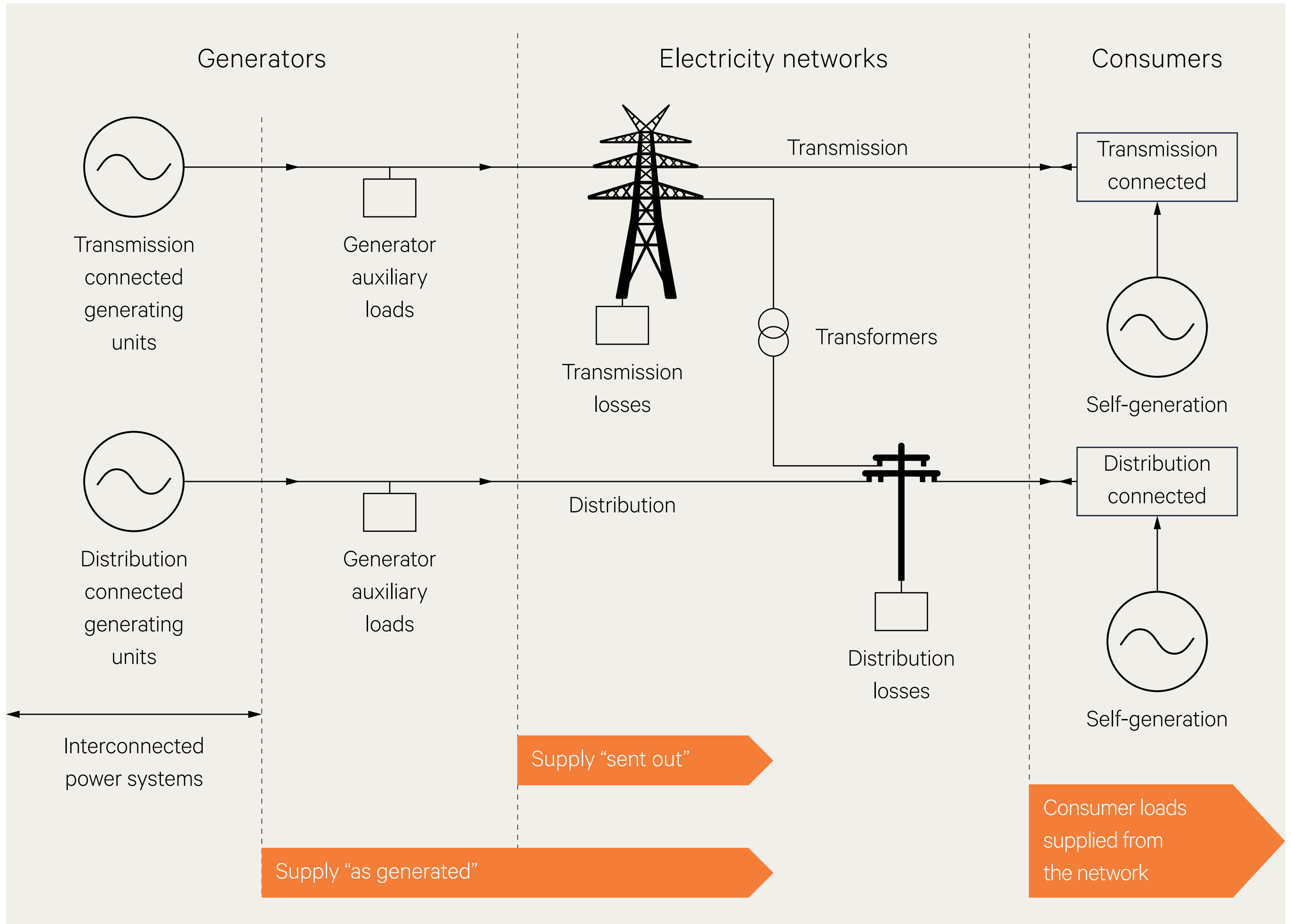
The NSW load forecast consists of medium, high and low future growth scenarios for annual energy and summer and winter maximum demands.

A1.1.1 Definitions

Figure A1.1 shows a typical power system such as that operating in the NSW region of the NEM. AEMO classifies each unit of generation connected to the NEM as either a scheduled, semi-scheduled or a non-scheduled generating unit. There are several potential points of measurement of energy flows and possible changes in direction of flows.

However, it is generally easier to record energy flowing into the network based on a relatively small number of generating units than to record the consumption of millions of consumers. Revenue meters are generally located at the connections of power stations with the network, and SCADA generally records large generating unit output.

Figure A1.1: Schematic power system[47]



"As generated" refers to energy or demand that includes generator auxiliary loads, and "sent out" refers to consumption or demand that excludes generator auxiliary loads.

"Native" energy is equal to "operational" energy as defined by AEMO, with the addition of energy supplied by non-scheduled generating units of less than 30 MW capacity, measured in GWh over a financial year. The operational measure includes generation by scheduled, semi-scheduled and non-scheduled generating units greater than or equal to 30 MW. TransGrid measures and forecasts native energy on a "sent out" basis.

"Native" demand is equal to "operational" demand as defined by AEMO, with the addition of demand supplied by non-scheduled generating units of less than 30 MW capacity. The operational measure includes generation by scheduled, semi-scheduled and non-scheduled generating units greater than or equal to 30 MW, measured in MW at a half-hourly resolution. TransGrid measures and forecasts native demand on an "as generated" basis.

47 Adapted from AEMO (2012) National Electricity Forecasting Report, Figure 2-1, p2-2.

A1.1.2 Recent NSW energy and demand compared to previous forecasts

The 2020 forecast of NSW region native energy for 2019/20 was 67,700 GWh, compared with an actual outcome of 68,600 GWh, an under-forecast of 900 GWh or 1.31 per cent. The forecast was based on a demand model informed by predicted input variables. TransGrid re-ran the forecasting model using actual right hand side (RHS) input variables to determine the extent to which the forecast outcome was driven by errors in predicted input variables, and the extent to which the model itself was inaccurate.

Table A1.1 shows the 2020 published medium forecast energy for 2019/20, the actual outcome and a new forecast using the same model with actual, rather than predicted values, for the input variables. The measures below show that the majority of the difference between the actual and forecast energy was due to the combined inaccuracy of all the input variables, rather than the model itself. In particular, the forecast fall in Gross State Product was many times greater than the actual fall, and household disposable income was forecast to fall, whereas it actually rose.

Notwithstanding this breakdown, the energy model one year ahead forecasting gap was relatively small, considering the challenges of forecasting the outcomes of the first year of the global COVID pandemic.

Table A1.1: 2020 medium energy forecast for 2019/20 compared with the actual outcome

	GWh	
Actual	68,600	
Published forecast	67,700	
New model-based prediction using actual RHS variables	70,189	
Forecasting gaps	**GWh**	**Difference**
Total gap (actual less published forecast)	900	1.31%
Model residual (actual less new model prediction)	-1,589	-2.32%
Error due to RHS variables and other inputs (total gap less model residual)	2,489	3.63%

There are two components to the assessment of the accuracy of MD forecasts. The first is a straightforward comparison between the actual and forecast POE levels. The second is the calculation of the unseen frequency distribution of possible seasonal MDs to determine the estimated POE levels. The accuracy of this process requires a certain level of judgement[48].

Table A1.2 shows the 2020 forecasts of 10%, 50% and 90% POE NSW region summer MD. These forecasts for summer 2020/21 were 94 MW lower to 48 MW higher (less than one percent difference) than the currently estimated POE values, based on actual data for the recent summer.

We estimate that the relatively low actual MD of 12,692 MW, which occurred in the half-hour ended 17:00 hours EST on Saturday 28 November 2020, represented a 73 per cent POE level of demand. This is the second summer in a row that the MD occurred on a Saturday. The highest weekday MD during summer 2020/21 was 12,449 MW in the half-hour ended 17:00 hours EST on Monday 25 January 2021.

The daily average temperature at the time of the 2020/21 summer MD was 33.6 degrees (5 per cent temperature POE), the highest of the season[49]. If this temperature had occurred on a weekday, we estimate that the MD would have been, at a minimum, 772 MW higher.

Table A1.2: 2020 medium maximum demand forecasts for summer 2020/21 compared with actual outcomes

	Actual MW	POE %	10% POE MW	50% POE MW	90% POE MW
Actual MD MW	12,692	73			
Estimated actual POE MD			14,288	13,397	12,083
Published forecast			14,382	13,356	12,035
Difference (estimated actual less published forecast)			-94	41	48
Average temperature degrees	33.6	5			

48 Weather correction of maximum demand and the estimation of POE levels is discussed in section A1.3 below.
49 Measured as the average of maximum and minimum daily temperatures at Parramatta. Records at this location date from June 1967.

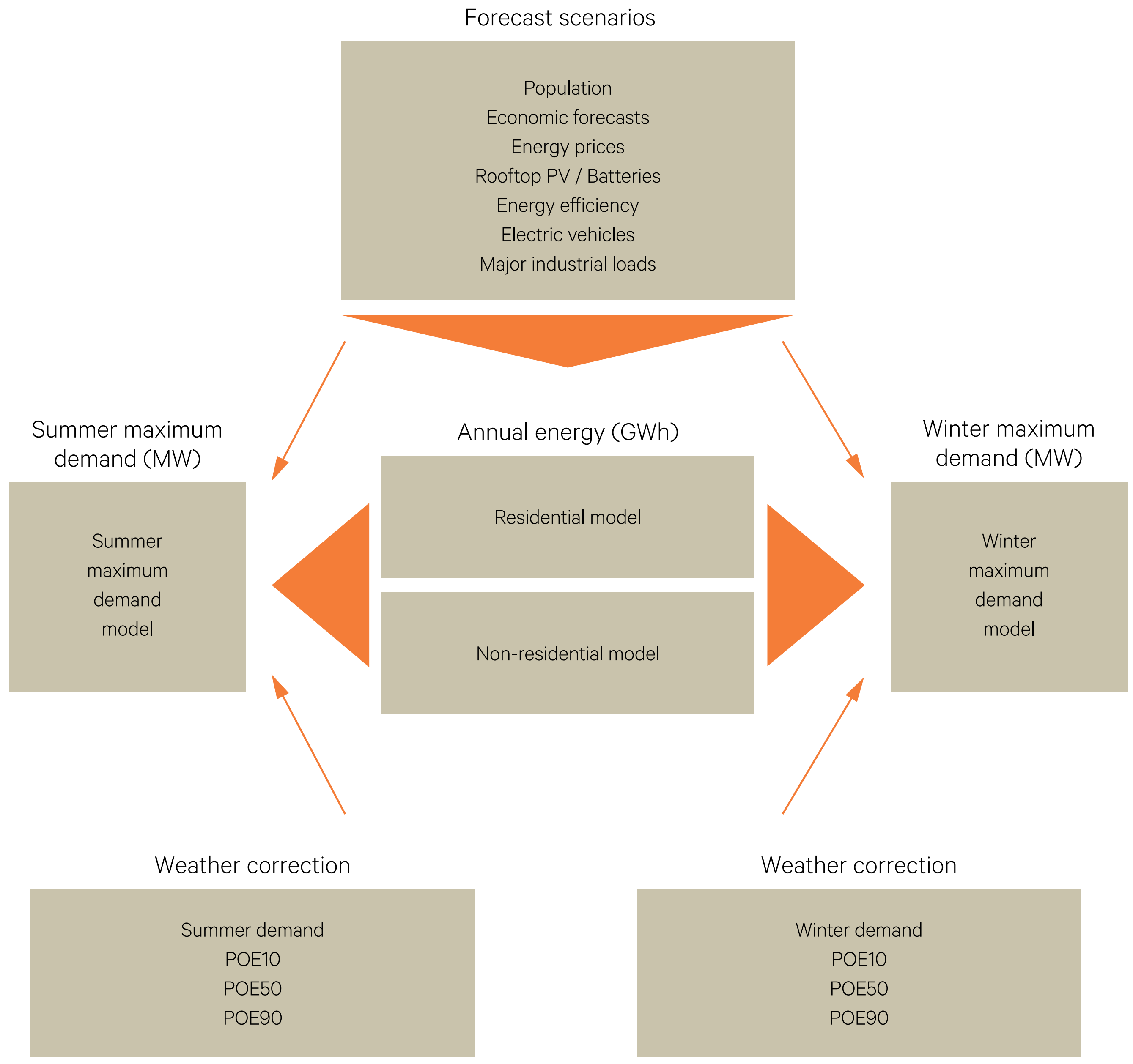
A1.1.3 Load forecast components

TransGrid prepared the 2021 NSW load forecast taking into account outputs from the following components:

- econometric modelling of the impacts of population, price, economic growth, weather and other drivers of underlying consumer behaviour – undertaken independently by TransGrid with help from GHD;
- weather correction of historical electricity maximum demands and the calculation of probability of exceedance levels – undertaken independently by TransGrid with help from GHD;
- regional demographic and economic forecast scenarios – provided by BIS Oxford Economics;[50]
- projections of future energy price paths – undertaken by Jacobs;[51]
- assessment of recent energy efficiency policies and standards, and quantification of the energy savings impacts – undertaken by Energy Efficient Strategies;[52]
- modelling of rooftop PV installation and generation, and distributed battery storage – undertaken by Jacobs;[53] and
- projections of the take-up of externally charging electric vehicles – undertaken by Energeia.[54]

Figure A1.2 presents these components schematically with their interactions and each is discussed in more detail in the following sections.

Figure A1.2: Overall schema



50 BIS Oxford Economics, Economic and Dwelling Forecasts to 2040 - NSW and ACT, Final, April 2021.
51 Jacobs, Retail Price Projections for NSW, Final Report, March 2021.
52 Energy Efficient Strategies, Projected Impacts of Energy Efficiency Programs, Final Report, May 2021.
53 Jacobs, Rooftop PV and Battery Scenarios, April-May 2021.
54 Energeia, Electric Vehicles Modelling March 2021, Report to TransGrid.

A1.2 Energy modelling

A1.2.1 Approach

Econometric modelling was used to estimate the independent impacts of population, electricity price, economic growth and weather on annual native electrical energy. Native energy is composed of electricity consumed by residential and major industrial customers. However, our energy modelling for 2021 includes overall analysis of total energy use for eight different end-use sectors. Previously we only modelled electricity consumed by residential and the generic non-residential sectors. The grid electricity share of each sector's energy use is derived from underlying trend shifts, changes in relative energy prices and the take-up of PV self-generation.

We estimated the effect of major drivers of energy consumption by constructing empirical models of energy use for the residential sector as well as seven ANZSIC[55]-derived industry sectors, including:

- Agriculture forestry and fishing (agriculture)
- Mining, excluding certain electricity customers included as "major industrial loads"
- Manufacturing, excluding certain electricity customers included as "major industrial loads"
- Gas, water and waste services (utilities), which excludes the use of energy used to generate electricity to avoid double-counting electricity generated
- Construction
- Commercial, which combines ANZSIC divisions F, G, H, J, K, L, M, N, O, P, Q, R and S
- Transport

For modelling purposes, energy consumption was defined as the end-use of grid-supplied and self-generated electricity, natural gas and all other fuels, plus an allowance for out-of-trend energy efficiency.

The primary source of historical energy data was Australian Energy Statistics[56]. This was supplemented by estimates of the out-of-trend impacts of energy efficiency measures and small-scale rooftop PV generation. The grid-supplied electricity historical data was extracted from TUOS as a sent out measure by TransGrid.

In all, eight separate auto-regressive distributed lag (ARDL[57]) models were designed to take account of the major drivers of energy use - population, price and income in the long-run, and temperature in the short-run. The models used projected future values for population, income and prices, and assumptions about mean temperature trends, to forecast total energy consumption for each sector.

The energy forecast output from each model was then converted to grid electricity forecasts using projected proportions of grid electricity to total energy for each sector, as well as out-of-trend energy efficiency, small-scale rooftop PV generation, distributed net battery charging and electric vehicle charging. The NSW electricity sent out forecast is equal to the sum of grid electricity for the eight identified sectors plus major industrial loads.

A1.2.2 Results

The efficiency-adjusted energy measure allows for the accurate identification of price impacts independently of changes in energy efficiency. The estimated forecasting equations resulted in identifying the sensitivities shown in **Table A1.3** and **Table A1.4**.

Table A1.3: Estimated long-run price and income elasticities of demand for energy in NSW

Sector:	Energy price (p-value)	Income (p-value)
Residential	-0.55 (0.00)	0.71 (0.00)
Agriculture	-0.60 (0.00)	0.42 (0.00)
Mining	-0.48 (0.30)	2.13 (0.00)
Manufacturing	-0.84 (0.00)	1.60 (0.00)
Utilities	n.a.	0.33 (0.32)
Construction	-0.54 (0.13)	0.36 (0.34)
Commercial	-0.08 (0.01)	1.58 (0.00)
Transport	-0.12 (0.04)	0.69 (0.01)

Table A1.3 For a one per cent increase in price or income, the long run impact on energy consumption (for the respective sector) is estimated to be the percentage change as indicated in the corresponding column. For example, an increase in the residential electricity price of one per cent would lead to a long-run decrease in residential electricity consumption (all other things remaining the same) of 0.55 per cent.

55 Australian and New Zealand Standard Industry Classification, https://www.abs.gov.au/ausstats/abs@.nsf/0/20C5B5A4F46DF95BCA25711F00146D75?opendocument.
56 Australian Energy Statistics, Department of the Environment and Energy, Australian Energy Statistics, Table F, September 2020
57 An ARDL model is a linear equation which provides for inclusion of one or more lagged dependent and independent variables. In a long run time series relationship where the equation errors are shown to have constant mean and variance, regardless of the sample chosen, are said to be cointegrated. Adoption of an ARDL technique in the case of cointegrated variables can be shown to have an equivalent error-correction equation form.

The p-values, presented in brackets in **Table A1.3** after the price and income elasticities, indicate the likelihood (in percentage terms) of an estimated value not being significantly different from zero. That is, a p-value close to zero indicates there is a very high likelihood the real value is not zero.

Short-run weather impacts are quantified as either heating or cooling degree days, or the temperature below or above the human comfort range inside buildings each day, for all days in a year. Future weather is modelled as a continuation of average warming trends over the last 30 years.

Table A1.4 shows estimated degree-day impacts on energy consumption, where a degree-day is the sum of degrees above or below a threshold temperature for all days in the year. The table shows, for example, that for each one degree-day increase in cooling requirements, NSW region residential and non-residential energy consumed increases by 5.5 GWh; similarly for each one degree-day increase in heating requirements, NSW region energy use increases by 2.6 GWh.

Table A1.4: Estimated short-run temperature sensitivities of annual energy in NSW

Sector:	Cooling	Heating
Residential	0.5	1.5
Non-Residential	5.0	1.1

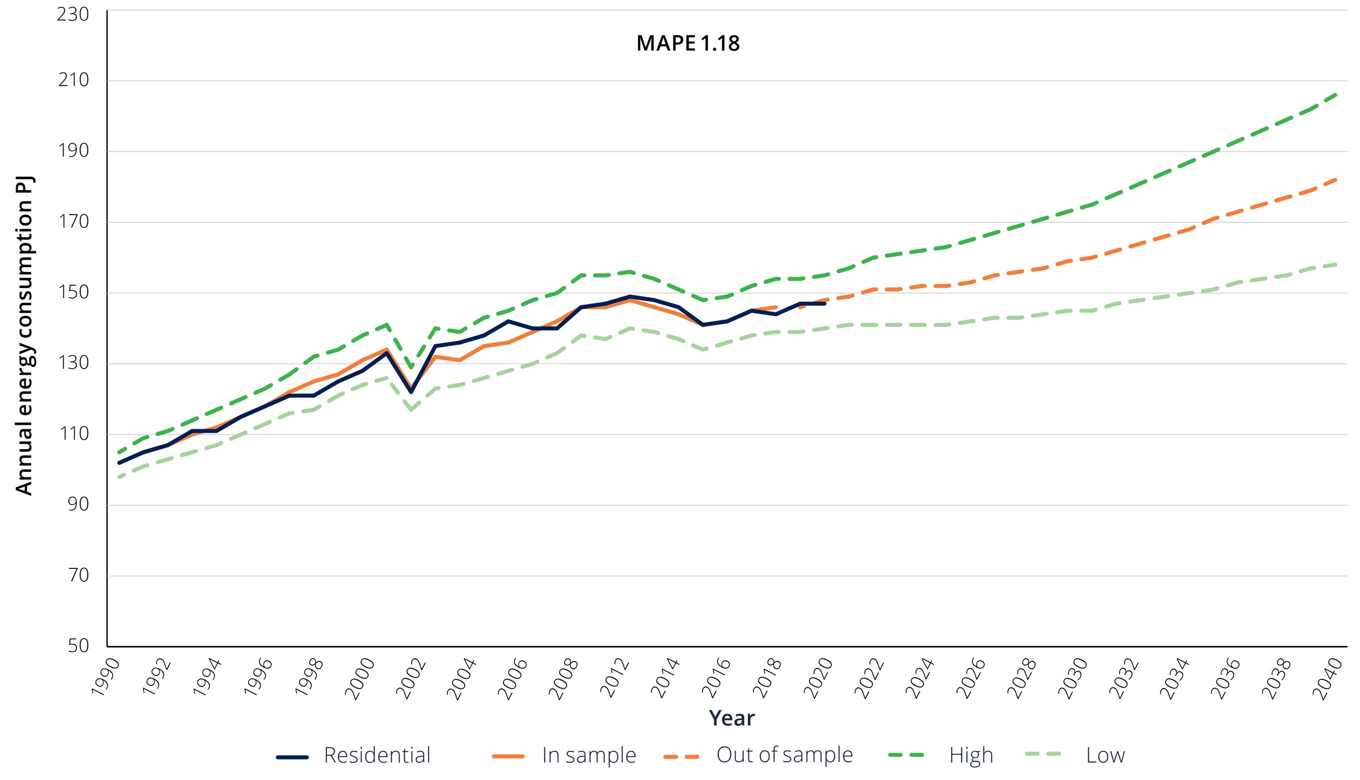
A1.2.3 Model accuracy

The residential and non-residential models' fit to the historical data sample and medium scenario forecasts are shown in the figures below. These figures were produced by re-estimating each forecasting equation using data only up to 2015-16, with the recent actual years forecast out-of-sample to test the models[58]. Some key indications of the reliability of the forecasts are:

- the fitted lines are contained within a plus or minus two standard error (high-low) band;
- the accuracy measures shown - Mean Absolute Percentage Error (MAPE) – are relatively low (1.18 for the residential model and 2.11 for the commercial model);
- there is little apparent bias indicating very little tendency for either model to produce long run forecasts that are persistently too high or too low; and
- the downturn in consumption starting in 2012 and mainly affecting the residential and commercial sectors, which is associated with rising prices and accelerating rooftop PV take-up, is picked up in varying degrees by the relevant models.

The evidence suggests that the models are valid across the entire sample period, are relatively accurate and are not given to persistent bias up or down.

Figure A1.3: Residential energy in-sample/out-of-sample fit[59]



58 The published energy forecasts have a starting point of 2021/22 and are based on actual and estimated data up to and including June 2021
59 In-sample fit refers to a forecast made with a model that is estimated using historical data including those covering the period forecast. An out-of-sample forecast is for a period outside the data sample that was used to develop the forecasting model.

Figure A1.4: Mining energy in-sample/out-of-sample fit

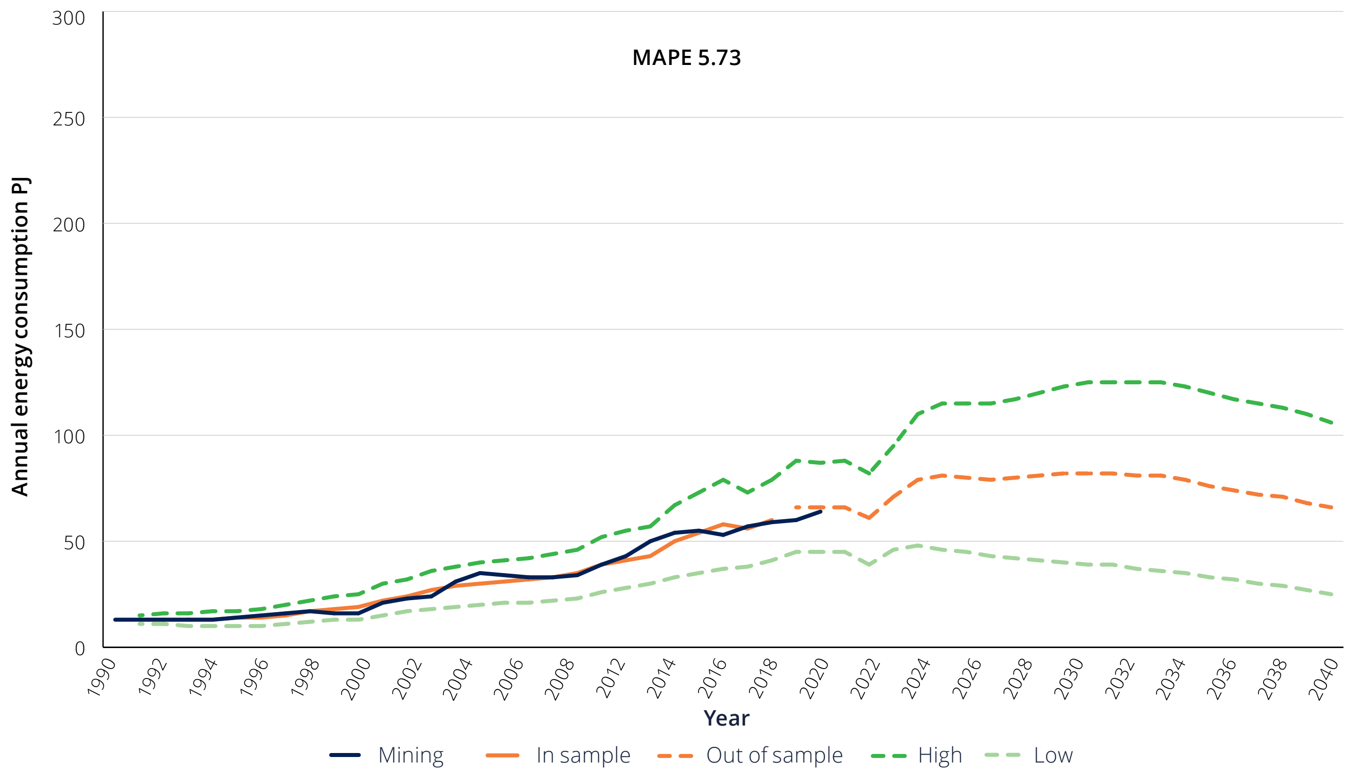


Figure A1.5: Manufacturing energy in-sample/out-of-sample fit

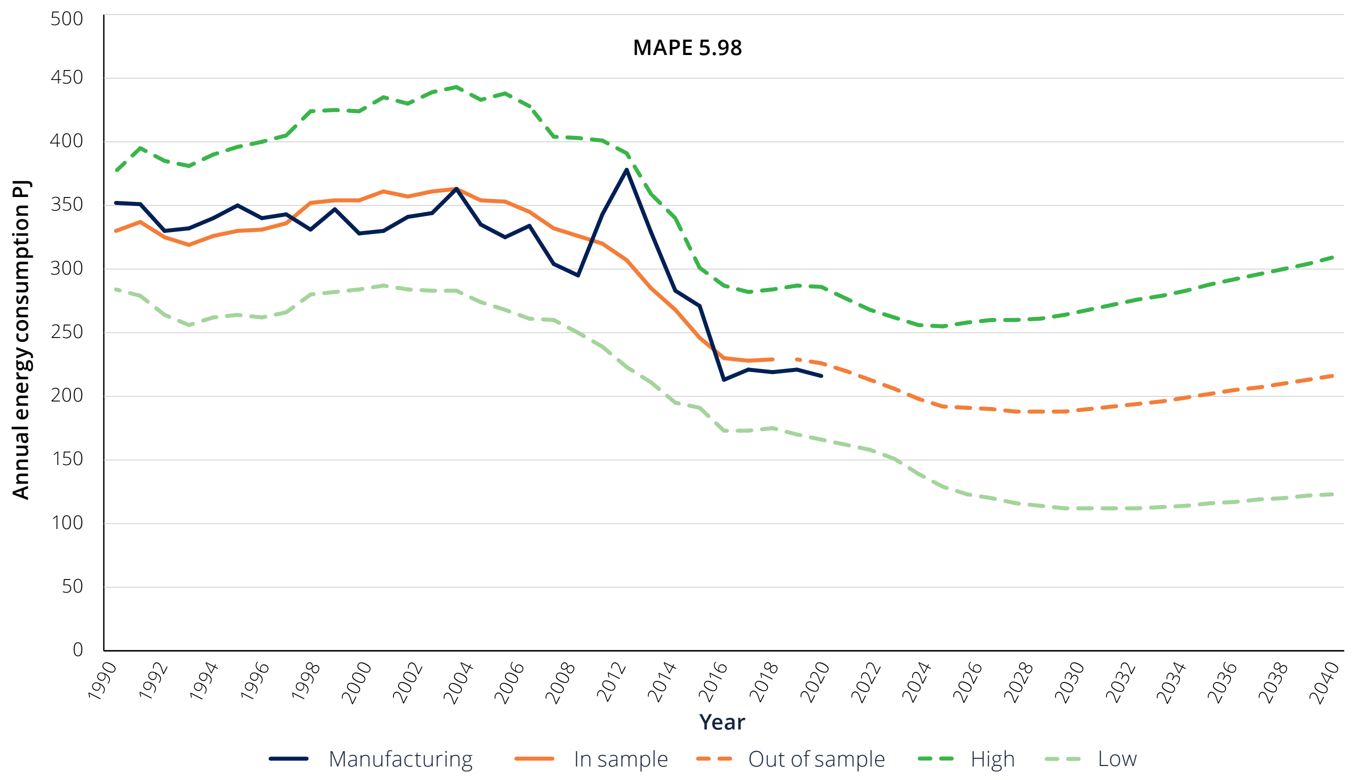


Figure A1.6: Construction energy in-sample/out-of-sample fit

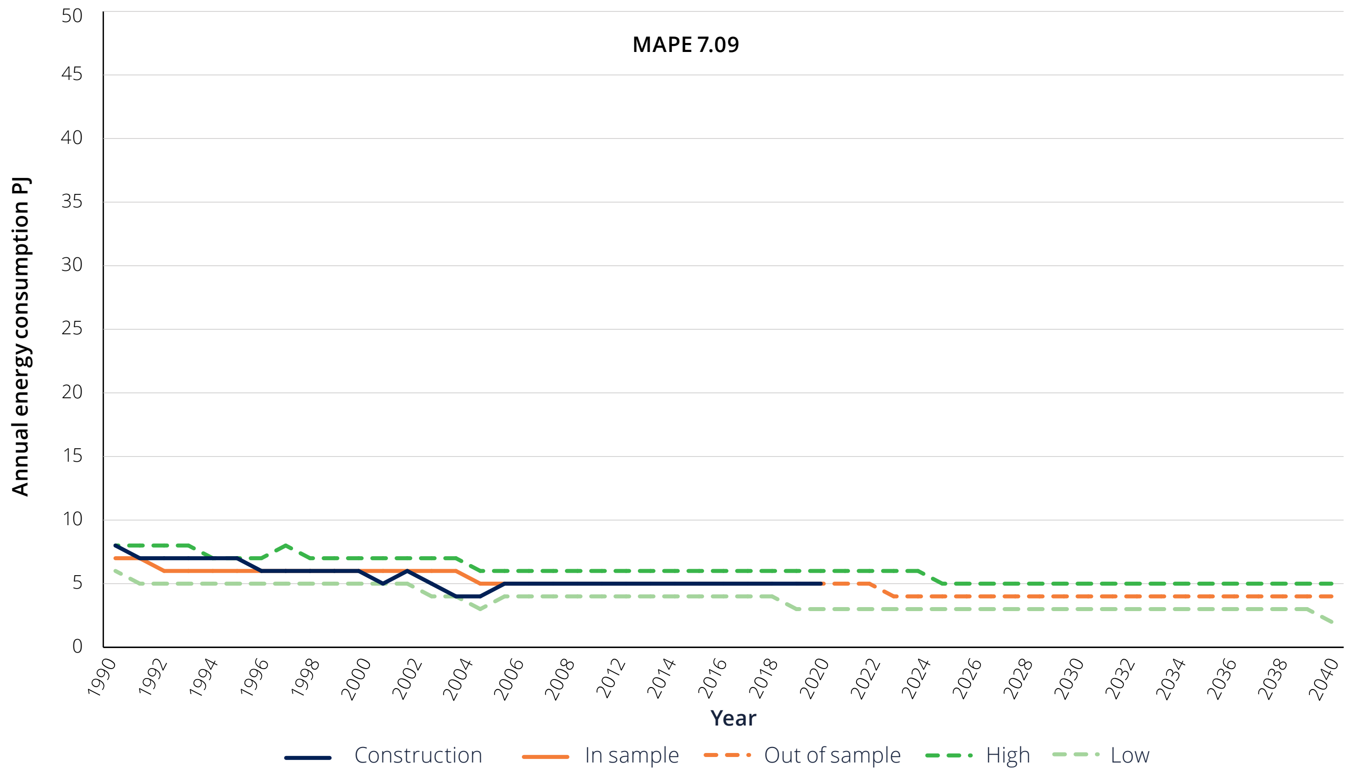


Figure A1.7: Commercial energy in-sample/out-of-sample fit

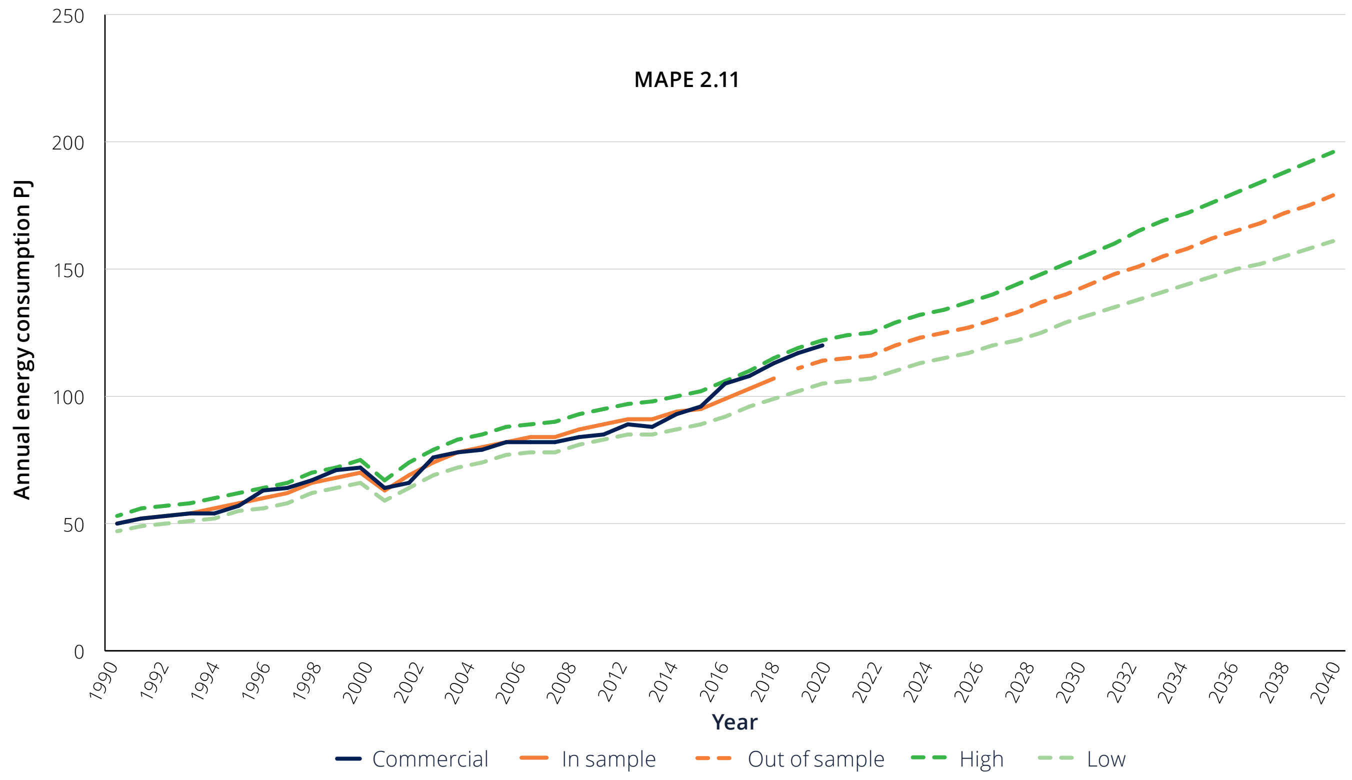
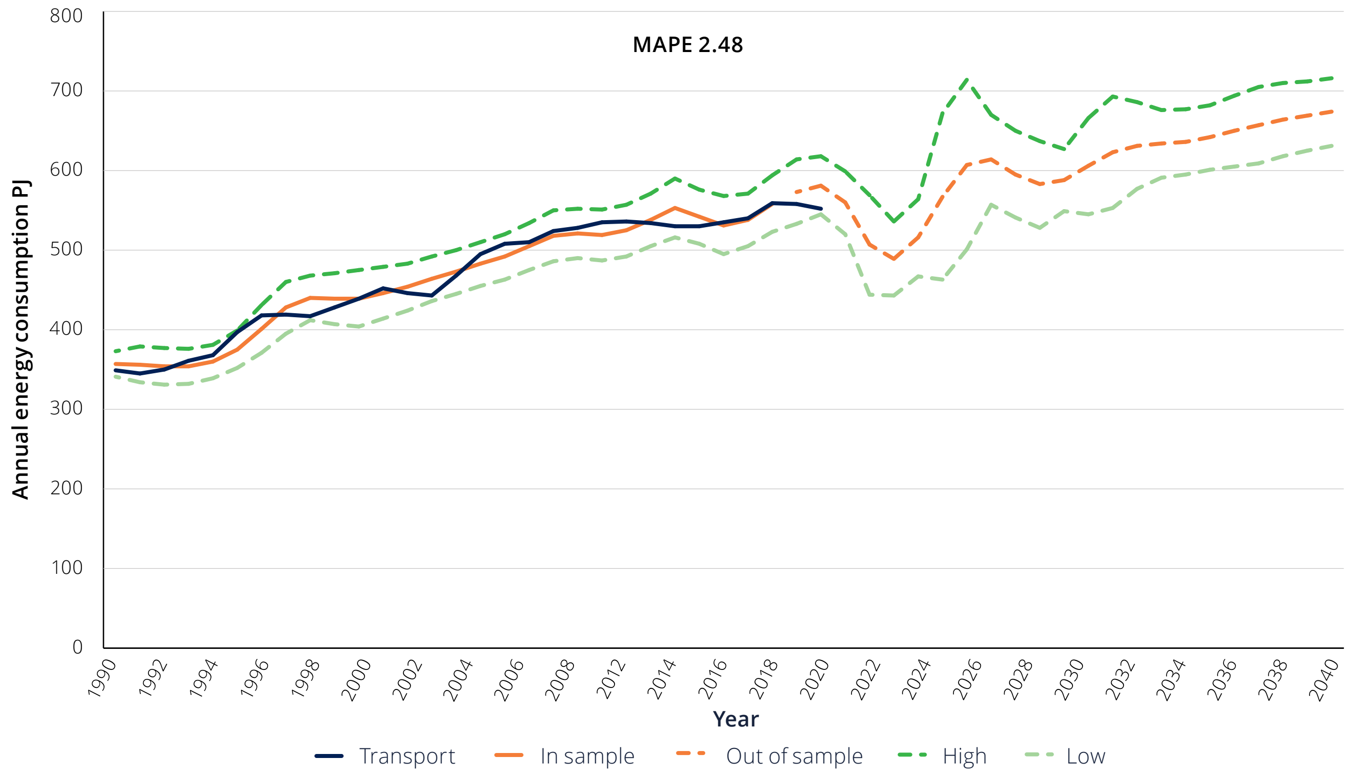


Figure A1.8: Transport energy in-sample/out-of-sample fit



A1.3 Weather correction of maximum demand

The purpose of weather correction of historical demands is to remove the influence of weather variation between consecutive seasons (summer or winter) and to calculate levels of maximum demand for each season that accurately correspond to 10, 50 and 90 per cent POE. Weather correction was carried out separately for summer and winter, using daily native maximum demand observations, and for one season at a time.

Below is a description of the three steps in the weather correction process, which is undertaken independently for each season (summer and winter) and for each historical year.

A1.3.1 Statistical estimation of a demand-temperature equation

- Inputs are daily maximum demand – carefully reconstructed using half-hourly operational demand and TransGrid's records of additional small non-scheduled generation – and measures of cooling degrees (for summer) and heating degrees (for winter);
- Only temperature and no other dimensions of weather are included – temperatures are the daily average of maximum and minimum temperatures at Sydney Observatory and Parramatta (for winter and summer respectively), with the summer measure using the minimum temperature from the following, rather than concurrent, morning;
- All days in a season are included, with dummy variables to account for weekends, public holidays and the two-week post-Christmas holiday period;
- A three-season rolling sample is used with dummy variables for the two previous seasons;
- A dummy variable for the months of January and February (a proxy for the coincidence of high working activity and the more frequent occurrence of high temperatures) is also included as it is found significant;
- Summer temperature sensitivity has more than doubled from 81 MW (1 per cent) per degree increase in average daily temperature in 1993-94 to 395 MW (3 per cent) in 2020-21; while the impact of an increase of one degree in the maximum daily temperature, for a similar daily average, brings about a further increase of 53 MW; and
- Winter temperature sensitivity has remained consistent in percentage terms at around 1.5 per cent, rising from 137 MW per degree in 1994 to 216 MW per degree in 2020.

A1.3.2 Historical temperature variation

- The selected method uses a range of daily temperatures drawn in historically accurate time sequence from the past 20 years;
- The data are transformed in the same manner as the temperature data used for estimating the demand-temperature equation; and
- Alternative temperature years for the respective season are substituted in the demand-weather equation to produce a variety of alternative demand traces for that-season.

A1.3.3 Synthesis of alternative residual values

- Since the statistical demand-temperature relationship is inexact, the residuals from the estimated equation represent variation in demand that is not explained by variation in temperature from one day to the next;
- The mean estimated residual value is zero, and the most accurate forecast of daily maximum demand over the entire season would assume a zero residual value;
- Seasonal maximum demand (the maximum of the daily maximum demands in a respective season) is most likely to occur on a working weekday with extreme temperature, and a high proportion of 'unexplained' demand variation – i.e. a large residual; and
- Statistically likely variation in the residuals is simulated by drawing from a random normal distribution with the same equation standard error as the equation that generated the original residuals. This assumes that: (i) actual residuals are independent of each other and randomly occurring; and (ii) drawn from a distribution that approaches a normal distribution with increasing sample size.

A1.3.4 Resampling process

- Alternative, randomly selected residual values (drawing from the same underlying distribution) are applied to each alternative temperature year demand trace, resulting in more alternative demand traces;
- For summer seasons, there are 20 alternative temperature sets and 600 alternative residual sets, resulting in a total of 12,000 alternative demand traces in each summer season; and
- For winter, there are 20 alternative temperature sets and 540 alternative residual sets, resulting in a total of 11,800 alternative demand traces in each winter season.

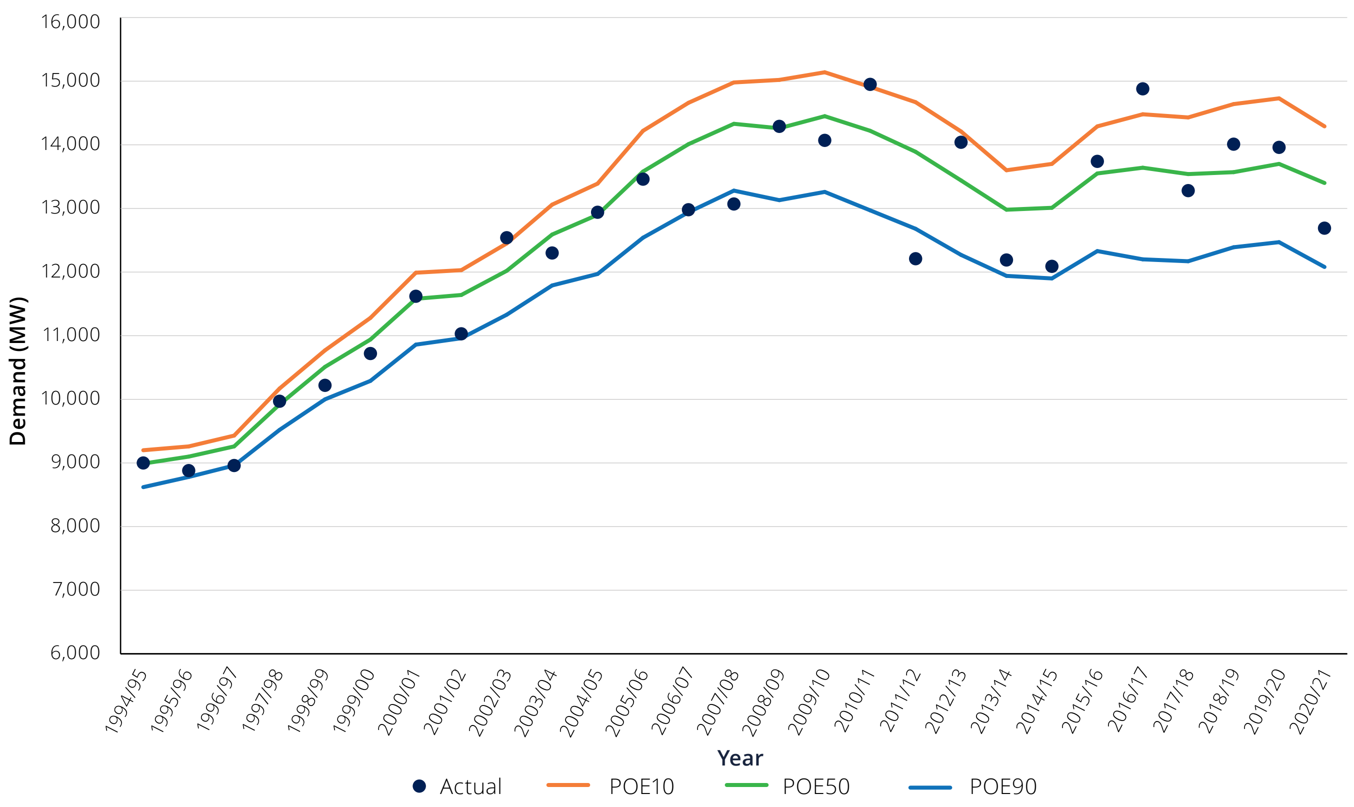
A1.3.5 Calculation of historical POE levels

- For each season, for each year, the maximum for each alternative demand trace is selected; and
- From each of the (approximately 12,000) alternative maxima for each season/year, the 90th, 50th and 10th percentiles are calculated as the POE10, POE50 and POE90 maximum demand levels, respectively.

A1.3.6 Results

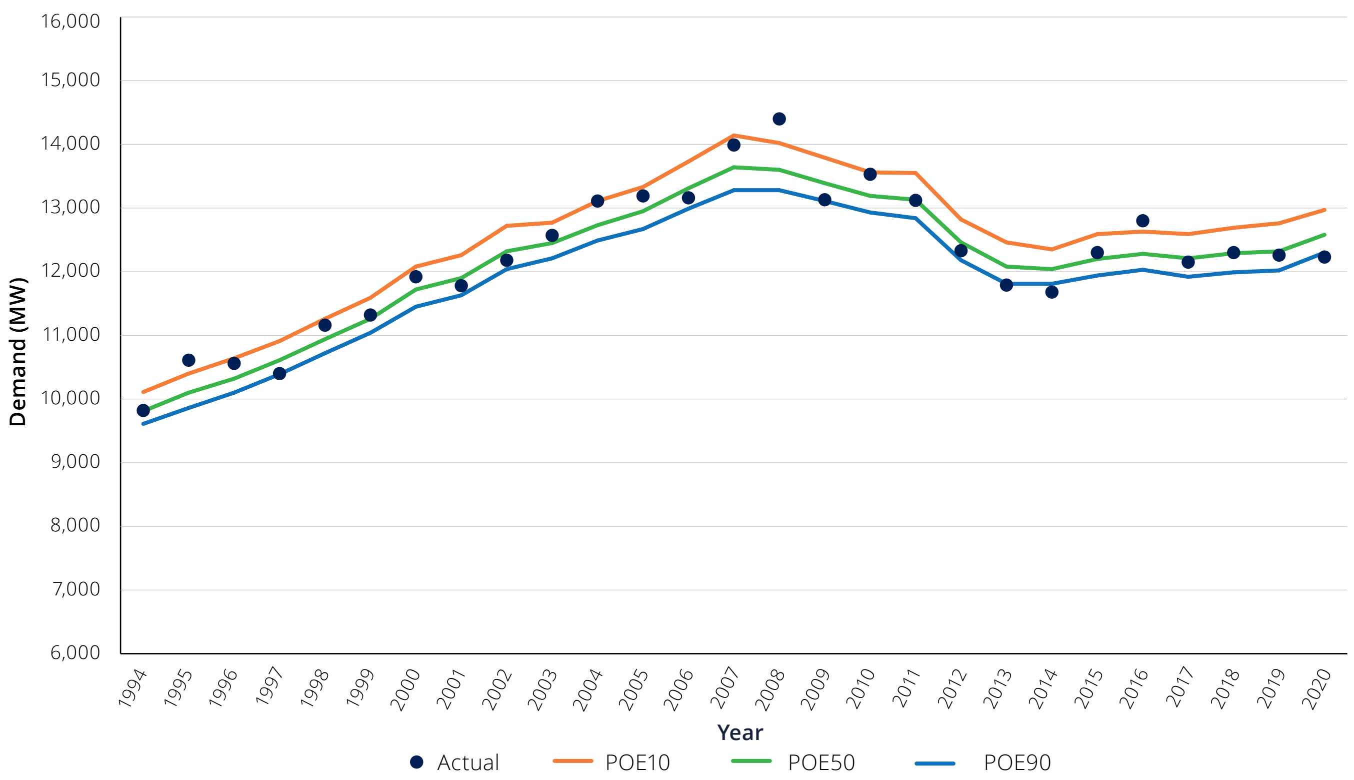
Historical maximum demands and the estimated POE10, POE50 and POE90 levels of demand are displayed in **Figure A1.9** and **Figure A1.10**.

Figure A1.9: Summer maximum demand



Source: TransGrid

Figure A1.10: Winter maximum demand



Source: TransGrid

A1.4 Summer and winter maximum demand models

A1.4.1 Approach to forecasting electricity services maximum demands

It is useful conceptually to break down the maximum level of demand reached in a particular season into the following components:

- underlying, weather non-sensitive demand driven by factors that are similar to those driving annual energy, including population growth, income growth and changes in energy prices;
- adjustments to underlying network demand at particular times of the day, due to explicit peak shifting measures and distributed energy resources such as rooftop PV generation and battery storage and discharge;
- specific investment plans and/or closures driving long-run changes in major industrial loads; and
- a highly variable, weather sensitive component which depends heavily on prevailing weather conditions.

The underlying non-weather sensitive component of demand may vary from year to year in line with annual energy. However, the weather-sensitive component is unlikely to be price-sensitive, as for the majority of consumers there is an insignificant impact on billing period energy charges for a few hours of additional consumption on a single day of extremely hot or cold weather.

In addition to traditional industrial loads, future electrification of transport will entail new sources of potential demand as a result of externally charged electric road vehicles. This may have a significant impact on maximum demands in the absence of incentives to charge outside of peak hours.

TransGrid's projections of summer and winter maximum demand are based on historical POE10, POE50 and POE90 underlying maximum demands, including estimated above-trend energy efficiency.

This removes the year-to-year variability due to weather-sensitivity and the impact of accelerated energy efficiency and DER.

The forecasts of underlying maximum demand are prepared as follows:

- major industrial loads are removed from each historical POE level of demand and annual energy;
- historical underlying maximum demands are calculated from the POE10, POE50 and POE90 levels of native maximum demand, plus the estimated impact of rooftop PV generation, out-of-trend energy efficiency and battery charging/discharging at the times of maximum demand;
- a statistical relationship is estimated between each POE level of maximum demand, annual energy and air-conditioning penetration;
- the estimated relationships are then used to predict future load factors, conditional on a projection of NSW air-conditioning penetration (currently around 73 per cent) that levels out around 80 per cent;
- the predicted underlying demands are used to generate a standard underlying demand profile for the day of summer and winter MD;
- the underlying demand profiles are adjusted by profiles for energy efficiency, PV, battery discharging and EV charging, thus allowing determination of the size and timing of the maximum native grid demand for the day.

This method maintains a link between the energy forecast and its underlying drivers and the level of maximum demand, maintains observed historical links between increasing air-conditioning penetration and growth in the weather-sensitive component of demand, and caters for timing as well as size effects of behind the meter activities such as PV generation.

A1.4.2 Calculating the impact and timing of distributed energy services and energy efficiency on electricity services

Average historical underlying MD profiles are generated by adding profiles for various DER elements to native MD profiles. The historical average shape of underlying demand is then maintained throughout the forecast period on a half-hourly basis for each day of MD.

Figure A1.11 and **Figure A1.12** show the construction of native POE50 MD for the 2029-30 summer and the 2029 winter. In each figure, underlying demand (i.e. demand in the absence of any DER) is shown by the blue line, while native demand (representing the net impact on the transmission network) is shown by the brown line. In that summer, the maximum underlying POE50 MD occurs at 16:00 hours EST, whereas, the impact of DER (mainly rooftop PV) is to both reduce and delay the maximum native MD until 17:00 hours EST.

Figure A1.11: Day of summer maximum demand 2030/31

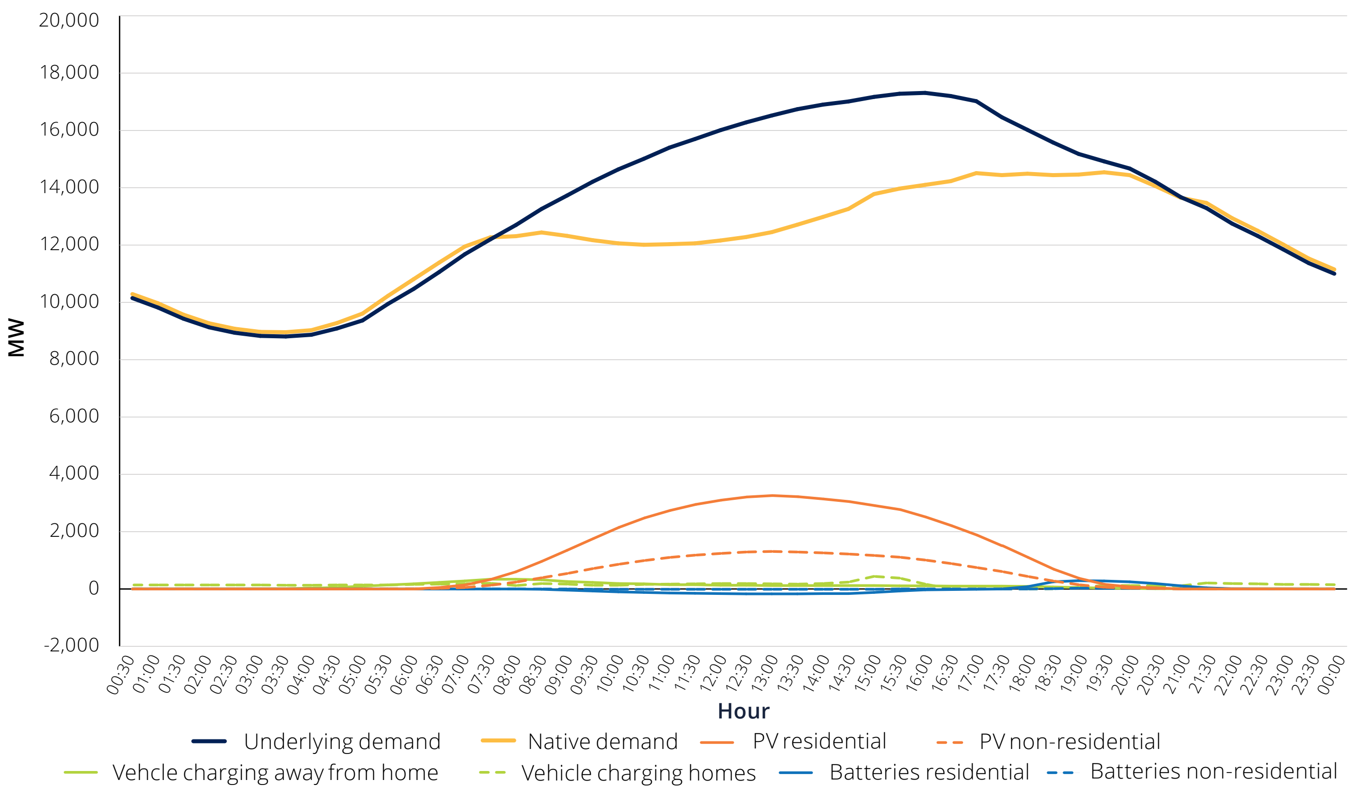
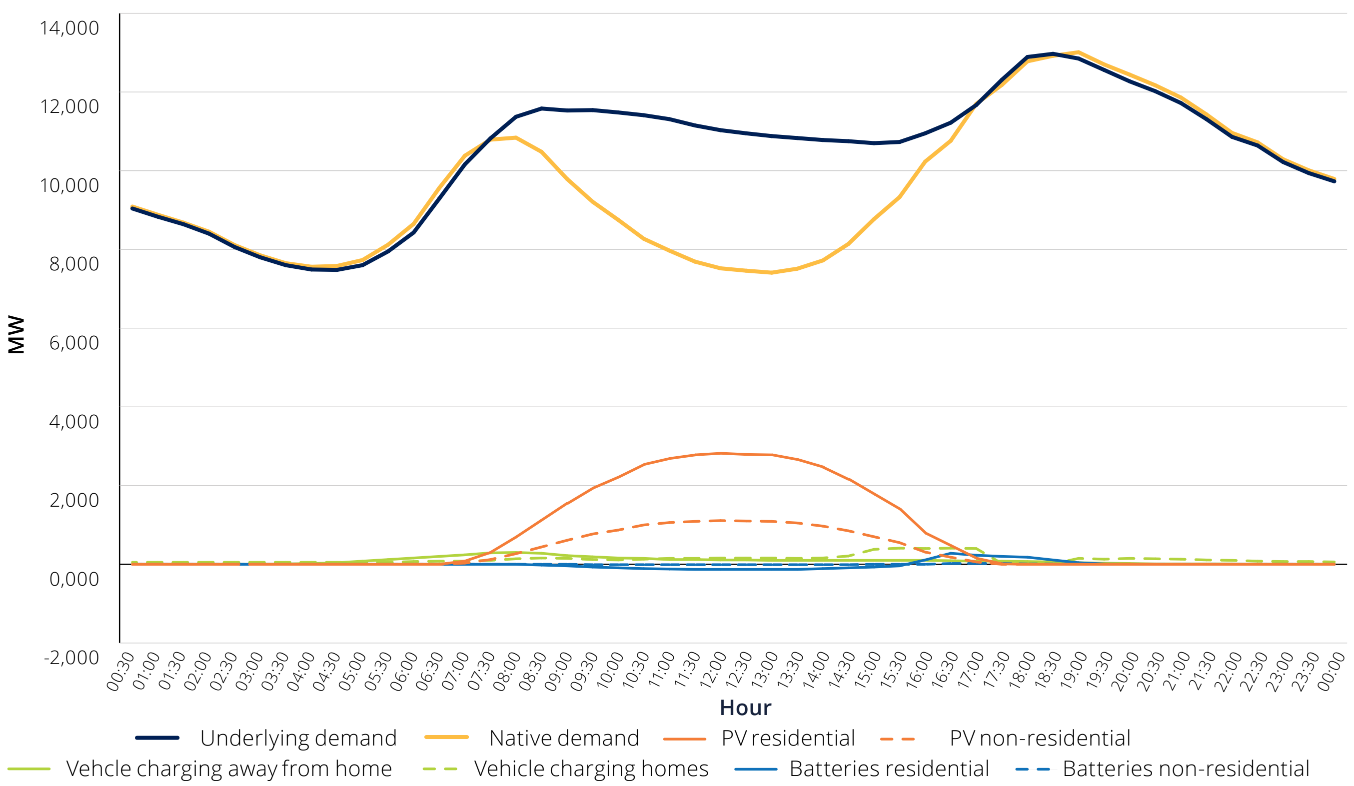


Figure A1.12: Day of winter maximum demand 2030



A1.4.3 Model accuracy

The summer and winter models' ability to fit the historical data sample and medium scenario forecasts are shown in **Figure A1.13 and Figure A1.14**. These figures were produced with data up to 2015-16 (summer) and 2016 (winter), with the last two to three actual years forecast out of sample to test the models[60]. Some key indications of the reliability of the forecasts are:

- the fitted lines are contained within a plus or minus two standard error band;
- the calculated accuracy measure of Mean Absolute Percentage Error (MAPE) is low (0.98 for summer and 1.36 for winter); and
- there is no persistent bias indicating no tendency for either model to produce long run forecasts that are either too high or too low.

The evidence suggests that the models are valid across the entire sample period, are relatively accurate and are not given to persistent bias up or down.

Figure A1.13: Electricity services summer maximum demand 50% POE in-sample/out-of-sample fit

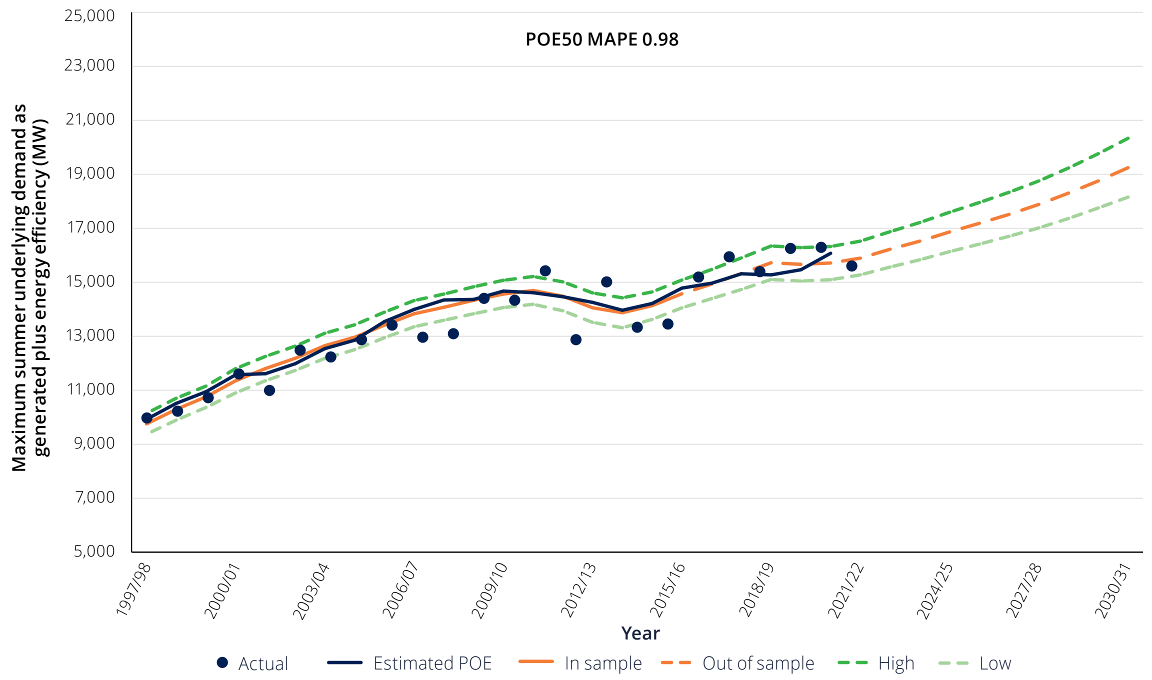
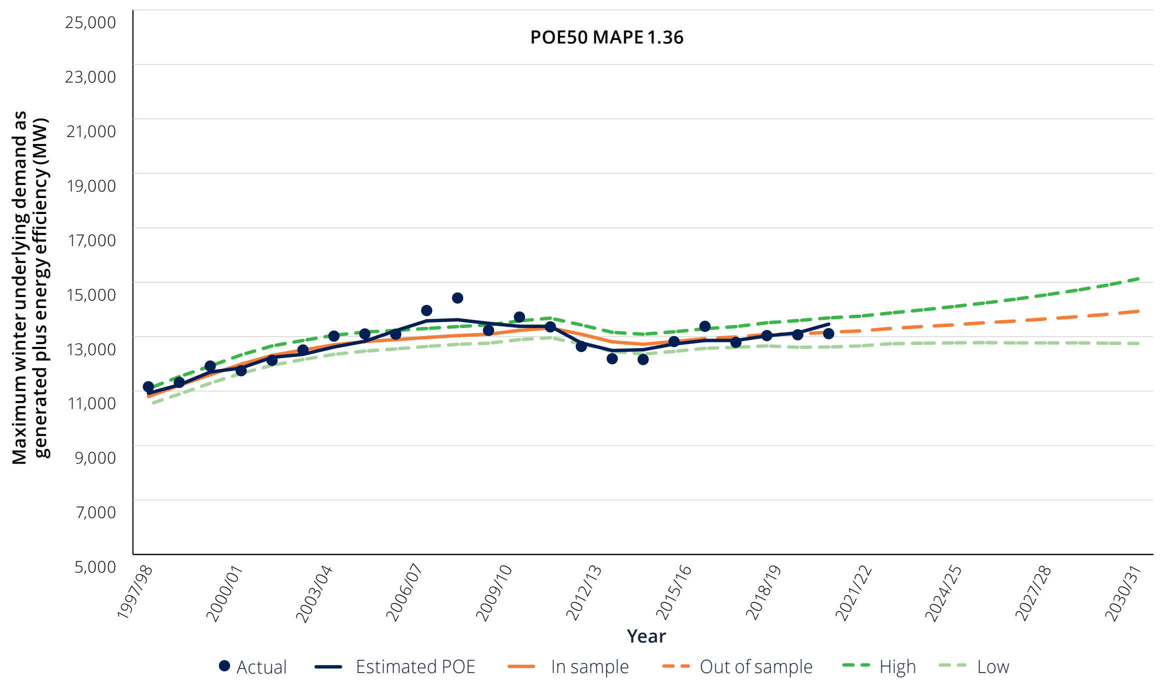


Figure A1.14: Electricity services winter maximum demand 50% POE in-sample/out-of-sample fit



60 The published forecasts of native MD have a starting point of 2020/21 (summer) and 2020 (winter), and are based on actual data up to and including March 2020. The estimated sample period fully includes summer 2019/20 and completely excludes winter 2020.

A1.5 Minimum demand model

TransGrid prepared a minimum demand forecast for publication for the first time in 2021. The half-hourly underlying NSW demand profile on days of low demand – typically weekends or holidays with little or no heating or cooling appliances in use – is relatively constant. Therefore, the minimum half-hourly demand in a financial year has generally followed the trend in average demand growth over time. The time of lowest network demand has traditionally been during night-time, in the early hours of 25 December or the following day. However, increasing behind-the-meter rooftop PV generation in New South Wales has contributed to reducing daytime network demands to less than the traditional overnight minimum demands.

Forecast network minimum demand was determined from a forecast of underlying minimum demand in a similar manner to the determination of summer and winter maximum demands. This involves overlaying the half-hourly underlying demand profile for the day of minimum demand with profiles for roof-top PV, distributed battery operation and electric vehicle charging, to calculate the corresponding network profile for the day. The minimum demand forecast is then taken to be the minimum half-hourly network demand for the day (usually between 1 and 2 p.m.).

The forecast underlying minimum demand profile was based on the average proportions of each half hour in the last four years using half-hourly profiles of minimum daytime demand days. The forecast growth was determined by fixing the half-hour of minimum demand as a fixed proportion of summer maximum demand, as this is historically reliable.

POE 50 minimum demand was estimated as the POE 50 summer maximum demand reduced by the proportion of the actual minimum to the actual maximum. Statistical modelling was then used to estimate a daily forecasting model for 50% POE minimum demand, from which the standard errors were used to determine POE 10 and POE 90 assuming a normal distribution.

A1.6 Major industrial loads

Major industrial loads accounted for 19 per cent of annual energy in 2020/21 and 11 per cent of MD for summer 2020-21 which occurred on 28 November 2020. Major industrial loads include the following electricity consumers:

- Tomago Aluminium;
- Bluescope steel Port Kembla;
- Onesteel Waratah West;
- Visy Gadara;
- Broken Hill Mine;
- Cadia Mine Orange;
- North Parkes Mine;
- Lake Cowal Mine;
- Ulan Area Mines;
- Boggabri East and North Mines; and
- CSR Oberon.

New major industrial load (spot loads) of up to 171 MW introduced over the next five years is included in the forecast. This increase was based on information on existing businesses' expansion plans and committed new business projects, provided by TransGrid's customers, including DNSPs. The increase, which includes mine expansions, new industrial loads and large infrastructure projects, has been discounted to account for future risks of these loads going ahead. This discount rate was derived from historical variations between planned load requirements for projects and actual outcomes.

A1.7 Input data and scenario assumptions

Inputs to the load forecasting framework described above were supplied from independent advice on the following issues affecting the long-run use of electricity in NSW.

The tables below show changes in input variables corresponding to each respective NSW region energy and demand scenario.

A1.7.1 Demographic and economic forecasts

TransGrid obtained projections of future demographic and economic trends.[61]

Table A1.5: NSW population growth and key macroeconomic forecasts CAGR 2021/22-2030/31

Variable	Medium	High	Low
Resident population	1.1	1.5	0.6
Real household disposable income	2.0	2.8	1.4
Gross State Product	2.3	3.2	1.6

61 BIS Oxford Economics (2021) Economic and Dwelling Forecasts to FY2040 – NSW & ACT, May 2021.

A1.7.2 Energy prices

Projections of future energy price paths were developed from the retail price projections report by using the yearly residential price changes and by averaging the separate non-residential price series.[62]

Table A1.6: NSW electricity and gas price forecasts CAGR 2021/22-2030/31

Variable	Medium	High	Low
Real residential electricity price	0.8	0.1	1.6
Real non-residential electricity price	0.7	-0.2	1.7
Real gas and other fuels price	3.2	3.4	3.1

A1.7.3 Rooftop PV and distributed battery storage

TransGrid rooftop PV and stationary battery charge/discharge forecasts were prepared by Jacobs[63]. Projected PV output and battery charging/discharging annual energy and profiles for specified days for all projected summer and winter periods were subtracted directly from the modelled energy and maximum demand forecast profiles, respectively, to estimate network energy and maximum demand.

Table A1.7: NSW rooftop PV and battery storage forecasts total increase 2021/22-2030/31 (2021-2030 for winter)

Variable	Medium	High	Low
Residential PV generation GWh	2,242	2,355	1,823
Non-residential PV generation GWh	1,563	1,719	1,370
Average shift in summer maximum demand due to PV and batteries (both due to capacity and time shift) MW	-2,254	-2,314	-2,159
Average battery charge (-) or discharge (+) at time of respective summer and winter system maximum demand MW	-9 / 13	-8 / 9	-9 / 11

A1.7.4 Energy efficiency policies

On behalf of TransGrid, Energy Efficient Strategies[64] conducted a thorough updated assessment of recent energy efficiency policies and standards, and quantified the aggregate energy savings impacts on electricity demand. TransGrid extracted the projected historical trend from 2000 to around 2010[65] from the projected total savings.

Table A1.8: Energy efficiency out of trend total increase 2021/22-2030/31 (2021-2030 for winter)

Variable	Medium	High	Low
Residential savings GWh	2,447	2,447	2,447
Non-residential savings GWh	4,383	4,383	4,383
Total savings at time of summer maximum MW	1,239	1,239	1,239
Total savings at time of winter maximum MW	883	883	883

62 Jacobs (2021) Retail Price Projections for NSW, Final, May 2021.
63 Jacobs (2021): Rooftop PV and Battery Forecasts, May 2021.
64 Energy Efficient Strategies (2021) Impact of Energy Efficiency Programs on Electricity Consumption in NSW and ACT, Report for TransGrid, May 2021.
65 The effects of energy savings measures on residential and non-residential energy and summer and winter maximum demand accelerated at different times between 2004 and 2010. The most recent (and forecast) trend was extracted from the earlier trend based on observations of these change points.

A1.7.5 Electric vehicles

An allowance is included in the load forecast to account for future take-up of externally charged electric vehicles. TransGrid has considered charging loads of existing electric vehicles and projected increasing take-up. The projections, including half-hourly profiles for specified days of interest, were sourced from Energeia[66].

Table A1.9: Electric vehicle charging total increase 2021/22-2030/31 (2021-2030 for winter)

Variable	Medium	High	Low
Annual charging energy GWh	2,710	2,710	1,351
Average charge at time of summer and winter MD MW	29 / 56	60 / 36	11 / 26

66 Electric Vehicle Uptake in NSW & ACT, Energeia - May 2021

A1.7.6 Glossary

Item	Description
As generated	Generation measured at the generator terminals
Cooling degree days	Cooling degree days is the addition of cooling degrees for all days in a period Cooling degrees (CD) are temperature deviations above a human comfort threshold, in this report taken to be 21 Celsius, therefore for a temperature measure t on any particular day, For t ≤21, CD = 0 For t >21, CD= t -21
Demand, Operational	A measure of electricity use based on half-hourly measurements of all Scheduled, Semi-Scheduled and significant Non-Scheduled generation within the region, plus net imports into the region
Demand, Native	Operational demand as above plus small Non-Scheduled generation. Non-inclusion of this generation may significantly distort past electricity usage trends in NSW
Elasticity	A unit-less measure of responsiveness of demand to either price or income. For example, an own price elasticity of -0.5 means that a 1% increase in own price reduces demand by 0.5%
Electricity services	This concept is used in TransGrid's energy modelling and refers to an underlying, primary need to use appliances that happen to be powered by electricity. It includes both residential electricity services and non-residential electricity services Residential electricity services is constructed as the addition of residential grid supplied energy, residential rooftop PV generation and estimated above-trend residential energy efficiency savings Non-residential electricity services is constructed as the addition of non-residential native energy (minus major industrial loads) non-residential rooftop PV generation and an estimate of out-of-trend non-residential energy efficiency savings
Energy	Measures the capacity for work to be done by electricity that is supplied to consumers, generally expressed in this report by the measure of GWh a year
Heating degree days	Heating degree days is the addition of heating degrees for all days in a period Heating degrees (HD) are temperature deviations below a human comfort threshold, in this report taken to be 18 Celsius, therefore for a temperature measure t on any particular day, For t ≥18, HD = 0 For t <18, HD = 18 -t
Load factor	The ratio of average demand to maximum demand. This can relate to maximum demand and energy via the formulation: Load factor = 1000 × GWh energy/(MW maximum demand × 8760)
Major industrial load	Electricity usage by a defined group of large electricity customers with whom TransGrid has a direct relationship and who are not significantly responsive to price or temperature
Maximum demand	Measures the highest rate, within a defined period such as summer or winter, at which energy is absorbed by the network, generally expressed in this report by the measure of MW averaged over a half-hour
NSW Region	State of NSW and the Australian Capital Territory (ACT)
Sent-out	Generation measured at the point of connection with the transmission network
Small non-scheduled generation	Non-Scheduled generation that is not included in Operational Demand
Spot Load	Spot loads are step (one-shot) increases in load for a BSP due to new commercial/housing developments or large industrial customer connections. There could be spot load decreases in cases where there are withdrawals of large load customers from the grid.
Summer	In this report, all days from 16 November in a particular year to 15 March in the immediately following year, inclusive
Winter	In this report, all days in a particular year from 16 May to 31 August, inclusive

Appendix 2

Individual bulk supply point projections

This appendix provides the maximum demand projections supplied by our customers for individual bulk supply points, based on local knowledge and the availability of historical data.

A2.1 Individual bulk supply point projections

Our customers have provided maximum demand projections, in terms of both megawatts (MW), megavolt ampere reactive (MVAr) and megavolt ampere (MVA) for individual bulk supply points between the NSW transmission network and the relevant customer's network. These projections are produced using methodologies that are likely to have been tailored to the circumstances relating to the load(s) at particular bulk supply point(s) such as the degree of local knowledge and the availability of historical data. The projections are given in the tables below.

Some large and relatively stable industrial loads mainly connected directly to TransGrid's network that we isolate for modelling purposes have been removed from the bulk supply point projections and aggregated. The removal of this data affects the projections shown for Broken Hill. Other industrial loads are included in bulk supply point forecasts provided by distributors. Aggregate projections for all identified major industrial loads (excluding those that are also in the bulk supply point forecasts) at the time of maximum NSW Region demand are given in **Table A2.11** and **Table A2.12**. Additional spot loads of about 120 MW are expected to be added to TransGrid's network in the next 10 years. These have been included in **Tables A2.11** and **A2.12**.

Table A2.1 to **Table A2.10** provide projections of non-coincident maximum demand occurring during a particular season at a particular bulk supply point (or group of bulk supply points) on the NSW transmission network. They do not represent projections of demand contributions at these bulk supply points to the overall NSW region maximum demand.

Table A2.1: Ausgrid bulk supply point summer maximum demand[67]

	2021/22			2022/23			2023/24			2024/25			2025/26		
	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA
Beaconsfield West 132 kV	346	31	347	363	-22	364	395	3	395	398	25	398	394	17	394
Rookwood Rd 132 kV	270	20	271	208	50	214	226	67	236	222	37	225	223	53	229
Haymarket 132 kV	416	84	425	446	63	450	473	58	477	481	117	495	475	58	478
Liddell 33 kV	19	9	22	19	9	22	19	9	22	19	9	22	19	9	22
Munmorah 132 kV & 33 kV	127	34	131	122	36	127	128	36	133	128	35	132	129	37	134
Muswellbrook 132 kV	196	106	223	197	104	223	197	105	223	196	105	222	195	105	221
Newcastle 132 kV	486	174	516	489	203	530	496	185	530	492	175	522	495	191	531
Sydney East 132 kV	656	2	656	674	-5	674	663	-13	663	663	4	663	664	7	664
Sydney North 132 kV	870	169	887	873	188	893	792	259	834	815	275	860	833	281	879
Sydney South 132 kV	1073	106	1078	1153	143	1162	1150	132	1158	1142	108	1147	1154	142	1162
Tomago 132 kV	348	105	364	329	92	342	351	120	371	351	102	366	348	88	359
Tuggerah 132 kV	233	104	255	236	98	255	235	100	256	231	73	243	232	78	244
Vales Point 132 kV	107	27	111	111	22	113	112	15	113	113	22	115	111	16	112
Waratah West 132 kV	241	82	254	236	72	247	240	86	255	239	84	253	239	88	255

	2026/27			2027/28			2028/29			2029/30			2030/31		
	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA
Beaconsfield West 132 kV	404	7	404	400	27	401	395	31	396	390	31	391	394	53	397
Rookwood Rd 132 kV	227	46	232	225	56	232	225	77	238	223	79	236	221	52	227
Haymarket 132 kV	477	111	490	476	132	494	473	91	481	472	93	481	476	109	488
Liddell 33 kV	19	9	22	19	9	22	19	9	22	19	9	22	19	9	22
Munmorah 132 kV & 33 kV	131	38	136	129	31	133	130	37	135	129	35	133	129	36	134
Muswellbrook 132 kV	194	104	221	193	103	219	192	104	218	191	103	217	191	103	217
Newcastle 132 kV	495	191	531	495	201	534	494	202	534	487	173	517	488	174	518
Sydney East 132 kV	670	6	670	673	19	674	675	19	676	676	12	676	677	10	677
Sydney North 132 kV	850	298	901	862	310	916	874	316	930	887	322	944	897	328	955
Sydney South 132 kV	1139	149	1149	1139	76	1142	1137	83	1140	1135	71	1137	1141	47	1141
Tomago 132 kV	349	87	360	351	91	362	352	95	364	354	104	369	355	105	370
Tuggerah 132 kV	232	78	245	232	84	247	230	78	243	228	73	239	229	74	240
Vales Point 132 kV	114	16	115	114	17	115	114	16	115	112	15	113	112	15	113
Waratah West 132 kV	238	87	254	235	71	245	234	69	244	234	82	248	235	82	249

Table A2.2: Ausgrid bulk supply point winter maximum demand[67]

	2021			2022			2023			2024			2025		
	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA
Beaconsfield West 132 kV	300	26	301	307	50	311	351	43	354	384	46	386	384	50	387
Rookwood Rd 132 kV	262	22	263	267	22	268	191	4	191	208	8	208	209	10	209
Haymarket 132 kV	358	67	364	367	67	373	390	98	402	419	119	435	415	95	426
Liddell 33 kV	17	8	19	17	8	19	17	8	19	17	8	19	17	8	19
Munmorah 132 kV & 33 kV	121	25	123	123	26	126	127	30	131	128	29	131	129	30	132
Muswellbrook 132 kV	169	83	188	170	84	190	170	82	189	170	82	189	170	82	189
Newcastle 132 kV	377	78	385	386	85	395	396	86	405	396	86	405	396	86	406
Sydney East 132 kV	655	1	655	677	20	677	682	22	682	691	21	691	694	26	695
Sydney North 132 kV	712	169	732	740	179	761	742	186	765	686	258	733	714	274	765
Sydney South 132 kV	936	34	936	950	37	951	998	18	998	1010	48	1011	1019	63	1021
Tomago 132 kV	265	50	270	269	53	274	281	64	288	280	65	288	281	66	288
Tuggerah 132 kV	212	82	227	218	90	236	223	83	238	225	91	242	226	93	244
Vales Point 132 kV	95	16	97	97	18	99	105	19	107	106	19	108	106	19	108
Waratah West 132 kV	186	40	191	192	43	196	188	44	194	189	44	194	189	44	194

	2026			2027			2028			2029			2030		
	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA
Beaconsfield West 132 kV	386	51	389	385	28	386	387	50	390	391	88	401	364	50	368
Rookwood Rd 132 kV	210	10	210	211	17	212	214	29	215	208	-9	208	202	28	204
Haymarket 132 kV	420	96	431	422	95	433	429	119	445	434	129	453	449	121	465
Liddell 33 kV	17	8	19	17	8	19	17	8	19	17	8	19	17	8	19
Munmorah 132 kV & 33 kV	130	30	134	131	30	134	131	31	134	131	30	135	134	26	136
Muswellbrook 132 kV	169	83	188	169	82	188	168	82	187	168	82	187	167	83	187
Newcastle 132 kV	397	87	407	399	88	408	400	89	410	400	89	410	404	84	413
Sydney East 132 kV	698	23	699	714	29	715	726	38	727	732	39	733	734	46	736
Sydney North 132 kV	736	287	790	754	298	811	772	310	832	792	320	854	801	205	827
Sydney South 132 kV	1029	78	1032	1041	102	1046	1041	51	1043	1044	39	1045	1071	58	1072
Tomago 132 kV	282	66	290	284	67	291	283	68	291	285	69	293	299	59	305
Tuggerah 132 kV	227	89	244	228	90	246	229	91	246	230	90	247	229	94	248
Vales Point 132 kV	107	19	109	107	20	109	108	20	110	108	20	110	106	21	108
Waratah West 132 kV	189	44	194	190	45	195	190	45	195	190	44	195	193	42	197

67 Zone substation projections aggregated to TransGrid bulk supply points using agreed load flow models.

Table A2.3: Endeavour Energy bulk supply point summer maximum demand[68]

	2021/22			2022/23			2023/24			2024/25			2025/26			2026/27			2027/28			2028/29			2029/30			2030/31		
	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA
Dapto 132 kV	516	86	524	525	87	532	530	88	537	538	89	546	540	89	547	543	90	550	544	90	552	547	91	555	549	91	557	551	91	559
Holroyd 132 kV	460	4	460	483	4	483	509	4	509	489	4	489	498	4	498	511	4	511	525	4	525	531	4	531	535	4	535	539	4	539
Ilford 132 kV	5	0	5	5	0	5	5	0	5	5	0	5	5	0	5	5	0	5	5	0	5	5	0	5	5	0	5	5	0	5
Ingleburn 66 kV	129	36	134	131	37	136	131	37	136	132	37	137	132	37	137	133	37	138	133	38	138	134	38	139	135	38	140	135	38	140
Liverpool 132 kV	444	76	450	470	81	477	486	84	493	497	86	505	515	89	523	524	90	532	532	92	539	539	93	547	545	94	553	551	95	559
Macarthur 132 kV & 66 kV	338	54	342	353	57	358	373	60	378	405	66	410	429	70	435	455	74	461	486	80	493	513	84	519	539	89	547	566	93	574
Marulan 132 kV	87	27	91	88	28	93	89	28	93	89	28	93	89	28	93	89	28	93	89	28	93	89	28	94	90	28	94	90	28	94
Mount Piper 66 kV	36	13	38	36	13	38	36	13	38	36	13	38	36	13	38	36	13	38	36	13	38	36	13	38	36	13	38	36	13	38
Regentville 132 kV	302	79	312	317	84	328	328	86	339	320	84	331	324	85	335	327	86	339	330	87	342	333	88	345	336	88	347	338	89	349
Sydney North 132 kV	38	11	39	39	11	40	39	11	41	40	11	41	40	11	42	40	11	42	41	12	42	41	12	43	41	12	43	42	12	43
Sydney West 132 kV	1326	344	1370	1403	364	1450	1488	386	1537	1567	407	1619	1629	423	1683	1690	438	1746	1736	450	1793	1769	459	1828	1781	462	1840	1793	465	1853
Vineyard 132 kV	541	100	550	583	107	593	644	118	654	692	127	703	727	134	739	762	140	775	797	147	810	829	153	843	856	158	871	884	163	899
Wallerawang 132 kV & 66 kV	64	15	66	64	15	66	64	15	66	64	15	66	64	15	66	64	15	66	64	15	66	64	15	66	64	16	66	65	16	66

Table A2.4: Endeavour Energy bulk supply point winter maximum demand[69]

	2021			2022			2023			2024			2025			2026			2027			2028			2029			2030		
	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA
Dapto 132 kV	701	106	708	716	108	724	721	109	729	728	110	736	736	111	744	740	112	748	742	112	751	745	112	754	747	113	756	749	113	758
Holroyd 132 kV	319	46	322	349	50	352	371	53	375	394	57	398	386	55	390	389	56	393	400	58	405	412	59	417	417	60	421	419	60	424
Ilford 132 kV	5	1	5	5	1	5	5	1	5	5	1	5	5	1	5	5	1	5	5	1	5	5	1	5	5	1	5	5	1	5
Ingleburn 66 kV	104	12	105	105	13	106	106	13	106	106	13	107	107	13	107	108	13	108	108	13	109	109	13	109	109	13	110	109	13	110
Liverpool 132 kV	344	43	346	374	46	377	401	50	404	418	52	422	433	54	436	447	55	450	455	56	459	463	57	466	469	58	472	474	59	477
Macarthur 132 kV & 66 kV	334	28	335	366	31	367	384	32	386	401	33	402	417	35	419	431	36	432	452	37	453	473	39	474	496	41	497	522	43	524
Marulan 132 kV	95	34	101	99	35	106	101	36	107	101	36	107	101	36	107	101	36	107	101	36	107	101	36	107	101	36	108	101	36	108
Mount Piper 66 kV	35	10	37	35	10	37	35	10	37	35	10	37	35	10	37	35	10	37	35	10	37	35	10	37	35	10	37	35	10	37
Regentville 132 kV	217	57	224	231	61	239	244	64	253	250	66	258	253	67	261	255	67	264	257	68	266	259	68	267	259	68	268	260	69	269
Sydney North 132 kV	25	4	26	26	4	26	26	4	27	27	4	27	27	4	27	27	4	28	27	4	28	28	4	28	28	4	28	28	4	28
Sydney West 132 kV	1025	243	1053	1137	270	1169	1201	285	1235	1276	303	1312	1348	320	1386	1407	334	1446	1462	347	1503	1503	357	1545	1535	365	1578	1546	367	1589
Vineyard 132 kV	372	40	375	407	44	409	451	48	453	506	54	509	544	58	547	582	63	586	619	66	622	655	70	658	687	74	691	716	77	720
Wallerawang 132 kV & 66 kV	73	16	75	74	16	76	74	16	75	74	16	75	74	16	75	74	16	76	74	16	76	74	16	76	74	16	76	74	16	76

Table A2.5: Essential Energy (North) bulk supply point summer maximum demand

	2021/22			2022/23			2023/24			2024/25			2025/26			2026/27			2027/28			2028/29			2029/30			2030/31		
	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA
Armidale 66 kV	28	1	28	28	1	28	28	1	29	28	1	28	28	1	29	28	1	28	28	1	28	28	1	28	28	1	28	28	1	28
Boambee South 132 kV	15	0	15	16	0	16	16	0	16	17	0	17	17	0	17	17	0	17	17	0	17	18	0	18	18	0	18	18	0	18
Casino 132 kV	32	6	32	32	6	33	32	6	33	33	6	33	33	6	33	33	6	34	33	6	34	34	6	34	34	6	35	34	6	35
Coffs Harbour 66 kV	53	0	53	53	0	53	54	0	54	55	0	55	56	0	56	56	0	56	57	0	57	58	0	58	58	0	58	59	0	59
Dorrigo 132 kV	2	1	3	2	1	3	2	1	3	2	1	3	2	1	3	2	1	3	2	1	3	2	1	3	2	1	3	2	1	3
Dunoon 132 kV	6	0	6	7	0	7	7	0	7	7	0	7	7	0	7	7	0	7	7	0	7	7	0	7	7	0	7	7	0	7
Glen Innes 66 kV	10	-2	10	10	-2	10	10	-2	10	10	-2	10	10	-2	10	10	-2	10	10	-2	10	10	-2	10	10	-2	10	10	-2	10
Gunnedah 66 kV	27	0	27	30	0	30	42	-3	42	42	-3	42	42	-3	42	42	-3	42	42	-3	42	42	-3	42	42	-3	42	42	-3	43
Hawks Nest 132 kV	11	1	11	11	1	11	12	1	12	12	1	12	12	1	12	12	1	12	13	1	13	13	1	13	13	1	13	13	1	14
Herons Creek 132 kV	11	2	11	12	2	12	12	2	12	12	2	12	12	2	12	12	2	12	13	2	13	13	2	13	13	2	13	13	2	13
Inverell 66 kV	39	-6	39	39	-6	40	40	-6	40	40	-6	41	41	-6	41	41	-6	42	42	-6	42	42	-6	43	43	-6	43	43	-6	44
Kempsey 33 kV	29	4	29	29	4	29	29	4	29	29	4	29	29	4	30	29	4	30	30	4	30	30	4	30	30	4	30	30	4	30
Koolkhan 66 kV	55	0	55	55	0	55	55	0	55	55	0	55	56	0	56	56	0	56	56	0	56	56	0	56	56	0	56	57	0	57
Lismore 132 kV	94	12	95	95	12	95	95	12	96	96	12	97	97	12	97	98	12	98	99	12	99	99	13	100	100	13	101	101	13	102
Macksville 132 kV	8	1	8	8	1	8	8	1	8	8	1	8	8	1	9	8	1	9	9	1	9	9	1	9	9	1	9	9	1	9
Moree 66 kV	29	0	29	28	0	28	29	0	29	28	0	28	29	0	29	29	0	29	29	0	29	29	0	29	28	0	28	28	0	28
Mullumbimby 132 kV	46	-2	46	46	-2	46	46	-2	46	46	-2	47	47	-2	47	47	-2	47	47	-2	47	47	-2	47	48	-2	48	48	-2	48
Nambucca 66 kV	7	-1	7	7	-1	7	7	-1	7	7	-1	7	7	-1	7	7	-1	7	7	-1	7	7	-1	7	7	-1	7	7	-1	7
Narrabri 66 kV	53	1	53	53	2	53	53	2	53	53	1	53	81	-2	82	82	-2	82	82	-2	82	85	-2	85	101	-4	101	101	-4	101
Port Macquarie 33 kV	63	6	64	64	6	65	66	6	66	67	6	67	68	6	68	69	6	70	70	6	71	71	7	72	73	7	73	74	7	74
Raleigh 132 kV	10	2	10	11	2	11	11	2	11	11	2	12	12	2	12	12	2	12	13	2	13	13	2	13	14	2	14	14	2	14
Stroud 132 kV	39	-2	39	39	-2	39	40	-2	40	40	-2	40	41	-2	41	41	-2	41	42	-2	42	42	-2	42	43	-2	43	43	-2	43
Tamworth 66 kV	127	25	130	127	25	130	128	25	130	128	25	131	129	25	131	129	25	131	129	25	131	129	25	132	129	25	132	130	25	133
Taree 33 kV	33	4	33	34	4	34	34	4	35	35	4	35	35	5	36	36	5	36	37	5	37	37	5	37	38	5	38	38	5	39
Taree 66 kV	56	6	56	56	6	57	56	6	57	57	6	57	57	6	57	57	6	58	57	6	58	57	6	58	58	6	58	58	7	58
Tenterfield 22 kV	4	0	4	4	0	4	4	0	4	4	0	4	4	0	4	4	0	4	4	0	4	4	0	4	4	0	4	4	0	4
Terranora 110 kV	85	9	86	86	9	87	92	10	92	92	10	92	92	10	93	93	10	93	93	10	94	94	10	94	94	10	95	95	10	95

Table A2.6: Essential Energy (North) bulk supply point winter maximum demand

	2021			2022			2023			2024			2025			2026			2027			2028			2029			2030		
	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA
Armidale 66 kV	41	2	42	42	2	42	42	2	42	42	2	42	42	2	42	42	2	42	42	2	42	42	2	42	42	2	42	42	2	43
Boambee South 132 kV	17	-1	17	17	-1	17	17	-1	17	17	-1	17	17	-1	17	17	-1	17	17	-1	17	17	-1	17	17	-1	17	17	-1	17
Casino 132 kV	22	2	22	22	2	22	22	2	22	22	2	22	22	2	22	22	2	22	22	2	22	22	2	22	22	2	23	23	2	23
Coffs Harbour 66 kV	58	-3	58	58	-3	58	59	-3	59	59	-3	59	59	-3	59	59	-3	59	59	-3	60	60	-3	60	60	-3	60	60	-3	60
Dorrigo 132 kV	3	1	3	3	1	3	3	1	3	3	1	3	3	1	3	3	1	3	3	1	3	3	1	3	3	1	3	3	1	3
Dunoon 132 kV	7	0	7	7	0	7	7	0	7	7	0	7	7	0	7	7	0	7	7	0	7	8	0	8	8	0	8	8	0	8
Glen Innes 66 kV	13	-2	14	13	-2	14	13	-2	14	13	-2	14	13	-2	14	13	-2	14	13	-2	14	13	-2	14	13	-2	14	13	-2	14
Gunnedah 66 kV	23	3	23	26	3	26	38	1	38	38	1	38	38	1	38	38	2	38	38	2	38	37	2	37	38	2	38	37	2	37
Hawks Nest 132 kV	9	1	9	9	1	10	10	1	10	10	1	10	10	1	10	10	2	11	11	2	11	11	2	11	11	2	11	11	2	12
Herons Creek 132 kV	12	1	12	12	1	12	12	1	12	12	1	13	13	1	13	13	1	13	13	1	13	14	1	14	14	1	14	14	1	14
Inverell 66 kV	33	-10	34	33	-10	34	33	-10	34	33	-10	35	33	-10	35	34	-10	35	34	-10	35	34	-10	35	34	-10	36	34	-10	36
Kempsey 33 kV	33	3	34	34	3	34	35	3	35	36	3	36	36	3	36	37	3	37	38	3	38	38	3	38	39	3	39	40	3	40
Koolkhan 66 kV	48	-7	48	48	-7	49	48	-7	49	49	-7	49	49	-7	49	49	-7	50	49	-7	50	50	-7	50	50	-7	50	50	-7	51
Lismore 132 kV	78	3	78	78	3	78	78	3	78	78	3	78	78	3	78	78	3	78	78	3	78	78	3	78	78	3	78	78	3	78
Macksville 132 kV	10	0	10	10	0	10	10	0	10	10	0	10	10	0	10	10	0	10	10	0	10	10	0	10	11	0	11	11	1	11
Moree 66 kV	28	1	28	28	1	28	28	1	28	28	1	28	28	1	28	28	1	28	28	1	28	28	1	28	28	1	28	28	1	28
Mullumbimby 132 kV	57	-1	57	58	-1	58	59	-1	59	60	-1	60	62	-1	62	63	-1	63	64	-1	64	65	-1	65	67	-1	67	68	-1	68
Nambucca 66 kV	9	0	9	9	0	9	9	0	9	9	0	9	9	0	9	9	-1	9	9	-1	9	9	-1	9	9	-1	9	9	-1	9
Narrabri 66 kV	49	7	49	49	7	49	49	7	49	49	7	49	77	6	78	78	6	78	78	6	78	81	6	81	97	5	97	97	5	97
Port Macquarie 33 kV	83	3	83	84	3	84	86	3	86	87	3	87	89	4	89	90	4	90	92	4	92	93	4	93	95	4	95	96	4	96
Raleigh 132 kV	11	1	11	11	1	11	11	1	11	11	1	11	11	1	11	11	1	11	12	1	12	12	1	12	12	1	12	12	1	12
Stroud 132 kV	32	-5	32	32	-5	33	33	-5	33	33	-5	34	34	-5	34	34	-5	34	34	-6	35	35	-6	35	35	-6	36	36	-6	36
Tamworth 66 kV	96	7	97	97	7	97	98	7	98	99	7	99	100	7	100	101	7	101	102	7	102	103	7	103	104	7	104	104	7	105
Taree 33 kV	27	2	27	27	2	27	27	2	27	28	2	28	28	2	28	28	2	28	28	2	28	29	2	29	29	2	29	29	2	29
Taree 66 kV	55	5	55	55	5	55	55	5	55	55	5	55	55	5	55	55	5	55	55	5	55	55	5	55	55	5	56	56	5	56
Tenterfield 22 kV	5	0	5	5	0	5	5	0	5	5	0	5	5	0	5	5	0	5	5	0	5	5	0	5	5	0	5	5	0	5
Terranora 110 kV	96	4	96	97	4	97	103	4	103	104	4	104	105	4	105	106	4	106	107	4	107	108	4	108	109	4	109	109	4	110

Table A2.7: Essential Energy (Central) bulk supply point summer maximum demand

	2021/22			2022/23			2023/24			2024/25			2025/26			2026/27			2027/28			2028/29			2029/30			2030/31		
	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA
Beryl 66 kV	84	12	85	84	12	85	85	12	86	86	13	87	86	13	87	87	13	88	88	13	89	89	13	89	89	13	90	90	13	91
Cowra 66 kV	35	-2	35	35	-2	36	36	-2	36	36	-2	36	36	-2	36	36	-2	36	36	-2	36	37	-2	37	37	-2	37	37	-2	37
Forbes 66 kV	33	-2	33	33	-2	33	32	-2	32	32	-2	32	32	-2	32	32	-2	32	31	-2	31	31	-2	31	31	-2	31	31	-2	31
Manildra 132 kV	10	4	11	10	4	11	10	4	11	10	4	11	10	4	11	10	4	11	10	4	11	10	4	11	10	4	11	10	4	11
Molong 66 kV	5	0	5	5	0	5	5	0	5	5	0	5	5	0	5	5	0	5	5	0	5	5	0	5	5	0	5	5	0	5
Mudgee 132 kV	26	1	26	27	1	27	27	1	27	27	1	27	28	1	28	28	1	28	29	1	29	29	1	29	30	1	30	30	1	30
Orange 66 kV	53	6	53	53	6	54	54	6	54	55	6	55	55	6	56	56	6	56	57	6	57	57	6	57	57	6	58	59	6	59
Orange 132 kV	170	22	171	187	25	188	184	24	186	183	24	185	184	24	186	183	24	185	184	24	185	184	24	186	184	24	186	188	25	189
Panorama 66 kV	67	10	68	69	10	69	69	10	70	70	11	71	71	11	72	72	11	73	73	11	74	74	11	75	75	11	75	76	11	77
Parkes 66 kV	29	3	29	31	2	31	31	2	31	30	2	31	30	2	31	30	2	30	30	2	30	30	3	30	30	3	30	30	3	30
Parkes 132 kV	39	12	41	44	13	46	52	16	54	52	16	54	52	16	54	52	16	54	52	16	54	52	16	54	52	16	54	52	16	54
Wallerawang 66 kV	5	0	5	5	0	5	5	0	5	5	0	5	5	0	5	5	0	5	5	0	5	5	0	5	5	0	5	5	0	5
Wallerawang 132 kV	26	15	30	26	16	30	26	16	31	27	16	31	27	16	32	27	16	32	28	16	32	28	17	33	28	17	33	29	17	33
Wellington 132 kV incl Town	185	13	185	185	13	185	185	13	185	185	13	185	185	13	185	185	13	185	185	13	185	185	13	185	185	13	185	185	13	185

Table A2.8: Essential Energy (Central) bulk supply point winter maximum demand

	2021			2022			2023			2024			2025			2026			2027			2028			2029			2030		
	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA
Beryl 66 kV	81	9	82	82	9	82	83	9	83	83	9	84	84	9	84	84	9	85	85	9	86	86	9	86	87	9	87	87	9	88
Cowra 66 kV	26	-2	26	26	-2	26	26	-2	26	26	-2	27	27	-2	27	27	-2	27	27	-2	27	27	-2	28	28	-2	28	28	-2	28
Forbes 66 kV	23	-3	23	23	-3	24	23	-3	24	23	-3	24	23	-3	23	23	-3	23	23	-3	23	23	-3	23	23	-3	23	23	-3	23
Manildra 132 kV	10	3	10	10	3	10	10	3	10	10	3	11	10	3	11	11	3	11	11	3	11	11	3	11	11	3	11	11	3	11
Molong 66 kV	5	-1	5	5	-1	5	5	-1	5	5	-1	5	5	-1	5	5	-1	6	6	-1	6	6	-1	6	6	-1	6	6	-1	6
Mudgee 132 kV	25	0	25	25	0	25	26	0	26	26	0	26	27	0	27	27	0	27	28	0	28	28	0	28	29	0	29	29	0	29
Orange 66 kV	68	7	68	68	7	68	69	6	69	69	6	70	70	6	70	71	6	71	71	6	71	72	6	72	72	6	72	73	6	73
Orange 132 kV	167	21	168	184	23	185	181	22	182	180	22	182	181	23	183	181	22	182	181	22	182	182	22	183	181	22	183	185	23	186
Panorama 66 kV	73	8	74	74	8	74	74	8	75	75	8	75	76	8	76	76	8	76	77	8	77	77	8	78	78	9	78	78	9	79
Parkes 66 kV	26	3	26	28	3	28	28	3	28	29	3	29	29	3	29	29	3	30	30	3	30	30	3	30	30	4	31	31	4	31
Parkes 132 kV	41	17	45	52	21	56	52	21	56	52	21	56	52	21	56	52	21	56	52	21	56	52	21	56	52	21	56	52	21	56
Wallerawang 66 kV	7	1	7	7	1	7	7	1	7	7	1	7	7	1	7	7	1	7	7	1	7	7	1	7	7	1	7	7	1	7
Wallerawang 132 kV	25	15	29	25	15	29	25	15	29	25	15	30	26	15	30	26	15	30	26	15	30	26	15	30	26	15	30	26	15	30
Wellington 132 kV incl Town	165	-2	165	166	-2	166	166	-2	166	166	-2	166	167	-2	167	167	-2	167	168	-3	168	168	-3	168	168	-3	169	169	-3	169

68 Marulan 132 kV: Both Endeavour Energy and Essential Energy take supply from Marulan. This forecast is for Endeavour Energy component. A diversity factor of 3% in summer should be applied to obtain the total forecast load at Marulan

69 Marulan 132 kV: Both Endeavour Energy and Essential Energy take supply from Marulan. This forecast is for Endeavour Energy component. A diversity factor of 2% in winter should be applied to obtain the total forecast load at Marulan

Table A2.9: Essential Energy (South) and Evoenergy bulk supply point summer maximum demand

	2021/22			2022/23			2023/24			2024/25			2025/26			2026/27			2027/28			2028/29			2029/30			2030/31		
	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA
Albury & Finley 132 kV	108	22	110	108	22	110	108	22	110	108	22	110	108	22	110	108	22	110	108	22	110	108	22	110	108	22	110	108	22	110
Balranald 22 kV	4	0	4	4	0	4	4	0	4	4	0	4	4	0	4	4	0	4	4	0	4	4	0	4	4	0	4	4	0	4
Broken Hill 22 kV	37	9	38	37	9	38	37	9	38	37	9	38	37	9	38	37	9	38	37	9	38	37	9	38	37	9	38	37	9	38
Canberra 132 kV Evoenergy	291	155	330	291	154	329	290	154	328	310	156	347	310	156	347	309	155	346	309	154	345	308	152	343	308	153	344	308	154	344
Coleambally 132 kV	13	5	14	13	5	14	13	5	14	13	5	14	13	5	14	13	5	14	13	5	14	13	5	14	13	5	14	13	5	14
Cooma 66 kV	17	1	17	17	1	17	17	1	17	17	1	17	17	1	17	17	1	17	17	1	17	17	1	17	17	1	17	17	1	17
Cooma 132 kV	40	-11	42	40	-11	42	40	-11	42	40	-11	42	40	-11	42	40	-11	42	40	-11	42	40	-11	42	40	-11	42	40	-11	42
Darlington Point 132 kV	19	-9	22	19	-9	22	19	-9	22	20	-9	22	20	-10	22	20	-10	22	20	-10	22	20	-10	22	20	-10	22	20	-10	22
Deniliquin 66 kV	42	1	42	42	1	42	42	1	42	42	1	42	42	1	42	42	1	42	42	1	42	42	1	42	42	1	42	42	1	42
Finley 66 kV	16	2	16	16	2	16	15	2	16	16	2	16	16	2	16	16	2	16	16	2	16	16	2	16	16	2	16	16	2	16
Griffith 33 kV	87	8	88	88	8	89	89	8	89	89	8	90	90	8	91	91	9	91	92	9	92	92	9	93	93	9	94	94	9	94
Marulan 132 kV	52	-9	53	53	-9	54	53	-9	54	54	-9	55	54	-10	55	55	-10	56	55	-10	56	56	-10	56	56	-10	57	57	-10	57
Morven 132 kV	7	1	7	7	1	7	7	1	7	7	1	7	7	1	7	7	1	8	7	1	8	8	1	8	8	1	8	8	1	8
Munyang 33 kV	3	-1	3	3	-1	3	3	-1	3	3	-1	3	3	-1	3	3	-1	3	3	-1	3	3	-1	3	3	-1	3	3	-1	3
Murrumbateman 132 kV	7	0	7	7	0	7	7	0	7	7	0	7	7	0	7	7	0	7	7	0	7	8	0	8	8	0	8	8	0	8
Murrumburrah 66 kV	35	7	36	35	7	36	35	7	36	35	7	36	35	7	36	35	7	36	35	7	36	35	7	36	35	7	36	35	7	36
Queanbeyan 66 kV Essential Energy	53	7	54	58	8	58	61	9	61	63	9	64	59	8	59	60	8	60	57	8	57	57	8	58	58	8	59	59	8	59
Queanbeyan 66 kV Evoenergy	22	11	25	22	11	25	21	10	23	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Queanbeyan 132 kV	9	-2	9	10	-2	10	11	-3	11	12	-3	12	19	-5	20	24	-6	25	14	-4	15	15	-4	16	16	-4	17	17	-4	18
Snowy Adit 132 kV	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Stockdill 132 kV Evoenergy	108	57	122	108	57	122	107	57	121	109	57	123	109	57	123	109	57	123	109	56	123	109	56	123	108	56	122	107	56	121
Tumut 66 kV	30	9	31	30	9	31	30	9	31	30	9	31	30	9	31	30	9	31	30	9	31	30	9	31	30	9	31	30	9	31
Wagga 66 kV	76	17	78	76	17	78	76	17	77	76	17	77	76	17	78	76	17	78	76	17	77	76	17	78	76	17	78	76	17	77
Wagga North 132 kV	62	-5	62	62	-5	62	63	-5	63	63	-5	63	63	-5	64	64	-5	64	64	-5	65	65	-5	65	65	-5	65	65	-5	66
Wagga North 66 kV	23	8	25	23	8	25	26	9	28	26	9	28	26	9	28	26	9	27	26	9	27	26	9	27	26	9	27	25	9	27
Williamsdale 132 kV Evoenergy	192	64	202	194	64	204	195	65	205	204	68	215	206	68	217	206	68	217	208	69	219	210	70	221	211	70	222	212	70	223
Yanco 33 kV	40	6	41	41	6	41	41	6	42	42	6	42	42	6	43	43	6	43	43	6	44	44	6	44	44	6	45	45	6	45
Yass 66 kV	13	-1	13	13	-1	13	13	-1	13	13	-1	13	13	-1	13	13	-1	13	13	-1	13	13	-1	13	13	-1	13	13	-1	13

Table A2.10: Essential Energy (South) and Evoenergy bulk supply point winter maximum demand

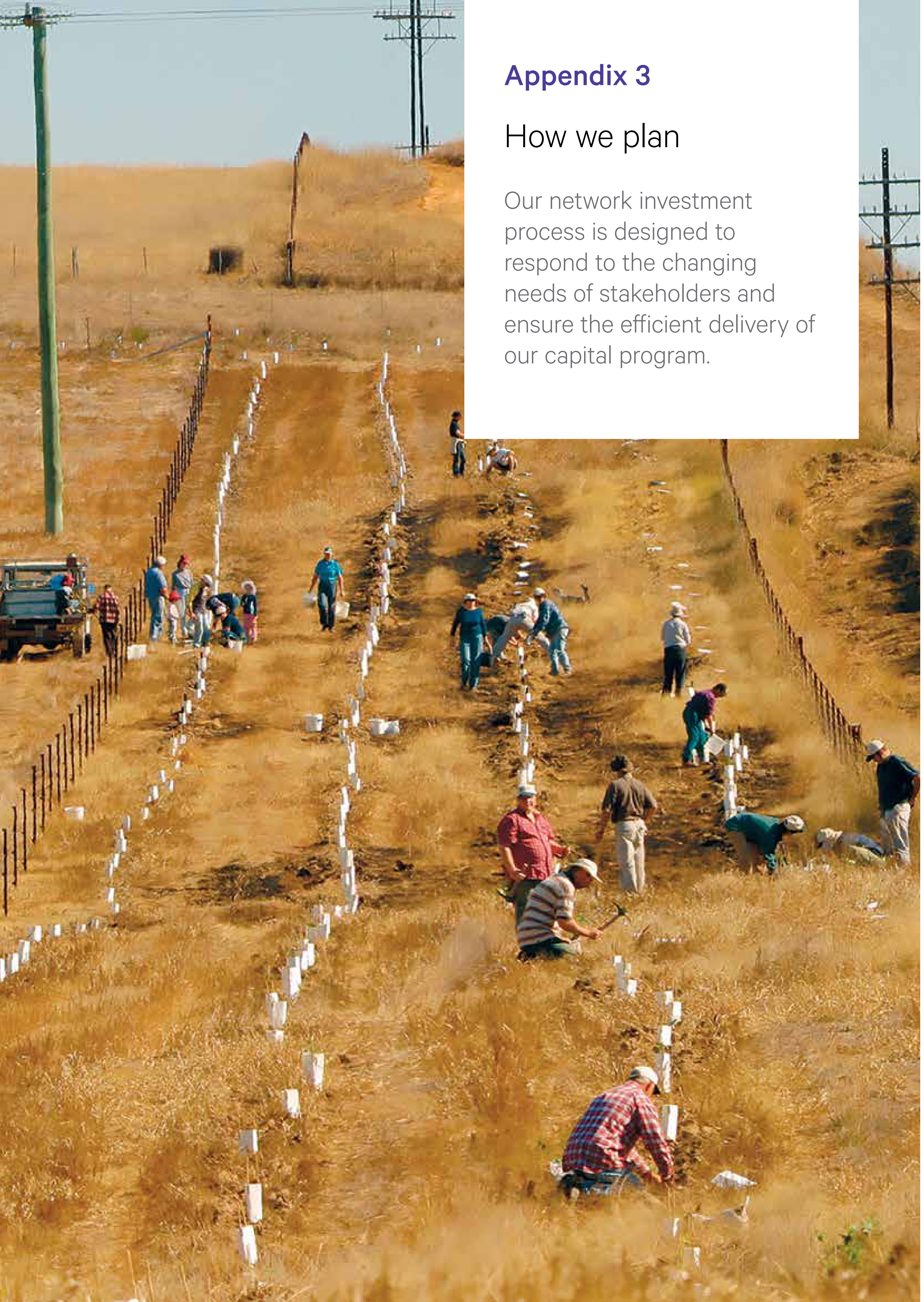
	2021			2022			2023			2024			2025			2026			2027			2028			2029			2030		
	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA
Albury & Finley 132 kV	93	6	93	93	6	93	93	6	94	94	6	94	94	6	94	94	6	94	95	6	95	95	6	95	95	6	95	96	6	96
Balranald 22 kV	3	-1	3	3	-1	3	3	-1	3	3	-1	3	3	-1	3	3	-1	3	3	-1	3	3	-1	3	3	-1	3	3	-1	3
Broken Hill 22 kV	34	2	35	35	2	35	35	2	35	35	2	35	35	2	35	35	2	35	35	2	35	35	2	35	35	2	35	35	2	35
Canberra 132 kV Evoenergy	354	140	381	355	140	382	355	140	382	355	141	382	375	143	401	376	143	402	376	143	402	376	144	403	377	143	403	377	144	404
Coleambally 132 kV	9	2	9	9	3	9	9	3	9	9	3	9	9	3	10	9	3	10	9	3	10	10	3	10	10	3	10	10	3	10
Cooma 66 kV	29	1	29	29	1	29	29	1	29	29	1	29	29	1	29	29	1	29	29	1	29	29	1	29	29	1	29	29	1	29
Cooma 132 kV	49	-13	51	50	-13	51	50	-13	52	50	-13	52	51	-13	52	51	-14	53	51	-14	53	52	-14	54	52	-14	54	52	-14	54
Darlington Point 132 kV	20	-14	24	20	-14	24	20	-14	24	20	-14	24	20	-14	24	20	-14	24	20	-14	24	20	-14	24	20	-14	24	20	-14	24
Deniliquin 66 kV	31	-1	31	31	-1	31	31	-1	31	30	-1	30	30	-1	30	30	-1	30	30	-1	30	29	-1	29	29	-1	29	29	-1	29
Finley 66 kV	12	-1	12	12	-1	12	12	-1	12	12	-1	12	12	-1	12	12	-1	12	12	-1	12	12	-1	12	12	-1	12	12	-1	12
Griffith 33 kV	53	4	54	54	4	54	54	4	55	55	4	55	56	4	56	56	4	56	57	4	57	57	4	58	58	4	58	58	4	59
Marulan 132 kV	55	-6	56	56	-6	56	57	-6	57	57	-6	58	58	-6	58	58	-7	59	59	-7	59	59	-7	60	60	-7	60	61	-7	61
Morven 132 kV	7	0	7	7	0	7	7	0	7	7	0	7	7	0	7	7	0	7	7	0	7	7	0	7	7	0	7	7	0	7
Munyang 33 kV	30	10	32	30	10	32	30	10	32	31	10	32	31	10	32	34	11	36	34	11	36	34	11	36	36	12	38	36	12	38
Murrumbateman 132 kV	7	0	7	7	0	7	8	0	8	8	0	8	8	0	8	8	0	8	8	0	8	9	0	9	9	0	9	9	0	9
Murrumburrah 66 kV	35	-2	35	36	-2	36	36	-2	36	36	-2	36	36	-2	36	36	-2	36	36	-2	36	36	-2	36	36	-2	36	37	-2	37
Queanbeyan 66 kV Essential Energy	66	2	66	71	2	71	74	3	74	76	3	76	72	3	72	72	3	72	69	2	69	70	2	70	70	2	70	71	2	71
Queanbeyan 66 kV Evoenergy	27	7	28	28	7	29	29	6	30	30	6	31	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Queanbeyan 132 kV	12	-2	12	13	-2	14	15	-2	15	16	-3	17	25	-4	25	30	-5	30	21	-3	21	22	-3	23	24	-4	24	25	-4	25
Snowy Adit 132 kV	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Stockdill 132 kV Evoenergy	138	54	148	138	54	148	138	54	148	138	55	149	140	55	150	140	55	150	140	55	150	141	55	151	141	55	151	141	55	151
Tumut 66 kV	33	12	36	33	12	36	33	12	36	33	12	35	33	12	35	33	12	35	33	12	35	33	12	35	33	12	35	33	12	35
Wagga 66 kV	69	5	69	68	5	68	68	5	68	67	5	67	67	5	67	66	5	66	66	5	66	65	5	65	65	5	65	64	5	64
Wagga North 132 kV	59	-11	60	59	-11	60	59	-11	60	59	-11	60	59	-11	60	59	-11	60	59	-11	60	59	-11	60	59	-11	60	59	-11	60
Wagga North 66 kV	22	2	23	22	2	22	25	2	25	25	2	25	25	2	25	25	2	25	25	2	25	25	2	25	25	2	25	24	2	25
Williamsdale 132 kV Evoenergy	200	49	206	202	49	208	204	50	210	206	50	212	215	52	221	217	53	223	218	53	224	219	53	225	221	54	227	223	54	230
Yanco 33 kV	33	4	34	33	4	34	33	4	34	33	4	34	33	4	33	33	4	33	33	4	34	33	4	33	33	4	33	33	4	33
Yass 66 kV	14	-3	15	14	-3	15	15	-3	15	15	-3	15	15	-3	15	15	-3	16	16	-4	16	16	-4	16	16	-4	16	16	-4	17

Table A2.11: Major industrial customers – Sum of individual summer maximum demands

	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Industrial Loads	1084	1148	1155	1159	1165	1169	1173	1177	1177	1171

Table A2.12: Major industrial customers – Sum of individual winter maximum demands

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Industrial Loads	1098	1096	1163	1169	1174	1177	1181	1185	1189	1189



Appendix 3

How we plan

Our network investment process is designed to respond to the changing needs of stakeholders and ensure the efficient delivery of our capital program.

A3.1 Network investment process

The network investment process adopted at TransGrid includes the following:

- An integrated, whole-of-business approach to capital program management;
- Optimisation of investments, and operating and maintenance costs, while meeting augmentation and asset management requirements;
- Early resolution of key risk areas such as environmental approvals, property acquisition and scope definition in the project delivery process; and
- Documented options evaluations and project scoping to enhance transparency.

The key processes and steps, including where and how we engage with stakeholders, are set out in the figure below.

Figure A3.1: Planning Methodology

		TransGrid planning process	Stakeholder involvement
STAGE 1	Identify need	Look at demand forecasts, expected generation patterns and the condition of existing assets. Will there be a shortfall in supply if we do nothing?	Sense-check forecasts with • Distributors • Directly connected customers • AEMO Seek feedback from end users and their representatives on need assessment.
STAGE 2	Review options	Identify possible network and non-network options to fulfil the need, including: • Demand management • Local or distributed generation • Network infrastructure optimised to expected requirements • Improved operational and maintenance regimes.	Input from large energy users, service providers and experts on potential for non-network options. Communicate with local community that may be impacted by network infrastructure.
STAGE 3	Plan in detail	Request proposals and undertake investment analysis on most viable options.	Encourage proposals from market participants for non-network options. Engage impacted communities in network corridor selection, if relevant. Involve end users and their representatives in final investment decision.
STAGE 4	Implement solution	Enter into contracts for network or non-network solutions. Build or renew network infrastructure, if required.	Work with impacted community to support best local outcomes. Report progress in meeting identified need to end users and their representatives.

Planning approach

As a TNSP, we are obliged to meet the requirements of the NER. In particular, we are obliged to meet the requirements of clause S5.1.2.1:

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

The NER sets out the required processes for developing networks as well as minimum performance requirements of the network and connections to the network. It requires us to consult with Registered Participants and interested parties and to apply the AER's Regulatory Investment Test – Transmission (RIT-T) as appropriate to development proposals.

Our planning obligations are interlinked with the reliability obligations placed on DNSPs in NSW. We must ensure that the network is adequately planned to enable these licence requirements to be met.

We plan the network to achieve supply at least cost to the community, without being constrained by state borders or ownership considerations.

The approach to network planning includes consideration of non-network options, including demand side response and demand management and/or embedded generation, as an integral part of the planning process. Joint planning with DNSPs, directly supplied industrial customers, generators and interstate TNSPs is carried out to ensure that the most economic options, whether network options or non-network options, consistent with customer and community requirements are identified and implemented.

Jurisdictional planning requirements

In addition to meeting the requirements of the NER, environmental legislation and other statutory instruments, we are required to comply with the Electricity Transmission Reliability Standards 2017, which came into effect on 1 July 2018. The standards use an economic probabilistic-based framework to determine the appropriate level of reliability for each of our bulk supply points. This TAPR has been prepared in accordance with our obligations in the standards.

The new probabilistic approach to determining the reliability standard at each of our bulk supply points has allowed us to develop alternate network plans with greater net market benefit, as demonstrated by using the cost-benefit methodology defined in the RIT-T process.

In fulfilling our obligations, we recognise specific customer requirements as well as AEMO's role as system operator for the NEM. We consider the following circumstances based on the demonstration of greater net market benefit than the requirement to merely comply with the new standard:

- Where agreed with a distribution network owner or major directly connected end-use customer, agreed levels of supply interruption can be accepted for particular single outages, before augmentation of the network is undertaken (for example, the situation with radial supplies);
- Where requested by a distribution network owner or major directly connected end-use customer and agreed with us, there will be no inadvertent loss of load (other than load which is interruptible or dispatchable) following events more onerous than N–1 such as concurrent outages of two network elements; and
- The main transmission network should have sufficient capacity to accommodate AEMO's operating practices without inadvertent loss of load (other than load which is interruptible or dispatchable) or uneconomic constraints on the energy market. AEMO's operating practices include the re-dispatch of generation and ancillary services following a first contingency, such that within 30 minutes the system will again be 'secure' in anticipation of the next critical credible contingency.

These jurisdictional requirements and other obligations require the following to be observed in the planning process:

- At all times when the system is either in its normal state with all elements in service or following a credible contingency:
  - Electrical and thermal ratings of equipment will not be exceeded;
  - Stable control of the interconnected system will be maintained, with system voltages maintained within acceptable levels;
- A quality of electricity supply at least to NER requirements is to be provided;
- A standard of connection to individual customers as specified by Connection Agreements is to be provided;
- As far as possible connection of a customer is to have no adverse effect on other connected customers;
- Environmental and social objectives are to be satisfied;
- Acceptable safety standards are to be maintained; and
- The power system in NSW is to be developed at the lowest cost possible whilst meeting the constraints imposed by the above factors.

A further consideration is the provision of sufficient capability in the system to allow components to be maintained in accordance with our asset management strategies.

Also, consistent with a responsible approach to the managing environmental impacts, the planning approach is also aimed at reducing system energy losses where it is economic to do so.

National planning requirements

AEMO has the role of the national transmission planner and is required to produce a NTNDP and ISP. The ISP, which incorporates elements of NTNDP, has regard to jurisdictional planning and regulatory documents (such as TAPRs) and, in turn, the jurisdictional planning bodies need to have regard to the NTNDP/ISP in formulating their plans. Our plans are consistent with the developments in the 2020 ISP.

The network planning process

The network planning process is undertaken at three levels:

1. Connection planning

Connection planning is focussed on local electricity networks that are directly related to the connection of loads and generators. Connection planning typically includes connection enquiries and the formulation of draft connection agreements leading to a preliminary review of the capability of connections. Further discussions are held with specific customers where there is a need for augmentation or for provision of new connection points.

2. Network planning within the NSW region

The main 500 kV, 330 kV and 220 kV transmission system is planned and developed in response to overall load growth and generation developments and may also be influenced by interstate power transfers through interconnections with other regions in the NEM. Any proposed developments are assessed through liaison with affected NSW and interstate parties using the joint planning processes.

The assessment of the adequacy of 132 kV bulk supply transmission systems requires that joint planning be undertaken in conjunction with DNSPs. This ensures that development proposals are optimal with respect to both transmission and distribution requirements, leading to the lowest possible overall network costs to the end customer. This is particularly important where the DNSP's network operates in parallel with the transmission network.

3. Inter-regional planning

The development of interconnectors between regions and of augmentations within regions that have a material effect on inter-regional power transfer capability are coordinated with network owners in other states in accordance with Clause 5.14.3 of the NER.

Consideration of non-network alternatives

Where economic to do so, our planning process includes consideration and adoption of non-network alternatives which can address the emerging constraints, and which may defer or cancel the need for some network augmentations. These opportunities are assessed on a case-by-case basis.

Compliance with NER requirements

Our approach to the development of the network since the commencement of the NEM is in accordance with the NER, other rules and guidelines published by the AER and the AEMC.

Planning horizons and reporting

Transmission planning is carried out over a short-term time frame of one to seven years, medium-term time frames of seven to 15 years and long-term time frames of 15 to 50 years. The short-term planning supports commitments to network developments with relatively short lead-times. The medium-term planning looks at currently emerging technologies and their impact on the power system. The long-term planning considers options for future major developments and provides a framework for the orderly and economic development of the transmission network and the strategic acquisition of critical line and substation sites.

In this TAPR, the constraints that appear over long-term time frames are considered to be indicative. The timing and capital cost of possible network options to relieve them may change as system conditions evolve.

Identifying network constraints and assessing possible solutions

An emerging constraint is identified during various planning activities covering the relevant planning horizon. It may be identified through:

- Our planning activities, including joint planning with DNSPs;
- The impact of network developments undertaken by other TNSPs;
- The impact of prospective generation developments;
- The occurrence of constraints affecting generation dispatch in the NEM; or
- As a result of a major load development.

During the initial planning phase, a number of options for addressing the constraint are developed. In accordance with NER requirements, consultation with interested parties is carried out to determine a range of options including network, demand management and local generation options and/or to refine existing network development options.

A cost-effectiveness or cost-benefit analysis is carried out, whereby the costs and benefits of each option are compared in accordance with the RIT–T process. The cost and benefit factors may include:

- Avoiding unserved energy caused by either a generation shortfall or inadequate transmission capability or reliability;
- Reduction in greenhouse gas emissions or increased capability to apply low emissions plant;
- Loss reductions;
- Alleviating constraints affecting generation dispatch;
- Avoiding the need for generation developments;
- More efficient generation and fuel type alternatives;
- Improvement in marginal loss factors;
- Deferral of related transmission works; and
- Reduction in operation and maintenance costs.

Options with similar net present value would be assessed with respect to factors that may not be able to be quantified and/or included in the RIT–T, but nonetheless may be important from environmental or operational viewpoints.

These factors include, but may not be limited to:

- Improvement in quality of supply above minimum requirements; and
- Improvement in operational flexibility.

Application of power system controls and technology

We seek to take advantage of the latest proven technologies in network control systems and electrical plant where it may be economic to do so. For example, the application of SVCs has had a considerable impact on the power transfer capabilities of parts of the main grid, and in the past has deferred or removed the need for higher cost transmission line developments.

Remidial action schemes have been applied in several areas of the NSW system to reduce the impact of network limitations on the operation of the NEM, and to facilitate the removal of circuits for maintenance.

The broad approach to planning and consideration of these technologies, together with related issues of protection facilities, transmission line design, substation switching arrangements and power system control and communication, is set out in the following sections. This approach is in line with international practice and provides a cost effective means of maintaining a safe, reliable, secure and economic supply system consistent with maintaining a responsible approach to environmental and community impacts.

A3.2 Planning criteria

Our planning obligations specify the minimum and general technical requirements in a range of areas including:

- A definition of the minimum level of credible contingency events to be considered for a specified allowance of unserved energy in a year;
- The power transfer capability during the most critical single element outage. This can range from zero in the case of a single element supply to a portion of the normal power transfer capability;
- Frequency variations;
- Magnitude of power frequency voltages;
- Voltage fluctuations;
- Voltage harmonics;
- Voltage unbalance;
- Voltage stability;
- Synchronous stability;
- Damping of power system oscillations;
- Fault clearance times;
- The need for two independent high speed protection systems; and
- Rating of transmission lines and equipment.

In addition to adherence to the NER and regulatory requirements, our transmission planning approach takes into account the historical performance of the components of the NSW system, the sensitivity of loads to supply interruption, and state-of-the-art asset maintenance procedures. It has also been recognised that there is a need for an orderly development of the system taking into account the requirement to meet future load and generation developments.

A set of criteria, detailed below, are applied as a point of first review, from which point a detailed assessment of each individual case is made.

Main transmission network

The NSW main transmission system is the transmission system connecting the major power stations and load centres and providing the interconnections from NSW to QLD and VIC. It includes the majority of the transmission system operating at 500 kV, 330 kV and 220 kV.

Power flows on the main transmission network are subject to overall State load patterns and the dispatch of generation within the NEM, including interstate export and import of power. AEMO applies operational constraints on generator dispatch to maintain power flows within the capability of the NSW and other regional networks. These constraints are based on the ability of the networks to sustain credible contingency events that are defined in the NER. These events mainly cover forced outages of single generation or transmission elements, but also provide for multiple outages to be redefined as credible from time to time. Constraints are often based on short-duration loadings on network elements, on the basis that generation can be re-dispatched to relieve the line loading within 15 minutes.

The rationale for this approach is that, if operated beyond a defined power transfer level, credible contingency disturbances could potentially lead to system-wide loss of load with severe social and economic impact.

Following any transmission outage, for example during maintenance or following a forced line outage for which line reclosure[70] has not been possible, AEMO applies more severe constraints within a short adjustment period, in anticipation of the impact of a further contingency event. This may require:

- The re-dispatch of generation and dispatchable loads;
- The redistribution of ancillary services; and
- Where there is no other alternative, the shedding (interruption) of load.

AEMO may direct the shedding of customer load, rather than operate for a sustained period in a manner where overall security would be at risk for a further contingency.

The risk is, however, accepted over a period of up to 30 minutes. We consider AEMO's imperative to operate the network in a secure manner.

The planning for the main network concentrates on the security of supply to load connection points under sustained outage conditions, consistent with the overall principle that supply to load connection points must be satisfactory after any single contingency.

The main 500 kV, 330 kV and 220 kV transmission system is augmented in response to the overall load growth and generation requirements and may be influenced by interstate interconnection power transfers. Any developments include negotiation with affected NSW and interstate parties including AEMO to maintain power flows within the capability of the NSW and other regional networks.

The reliability of the main system components and the ability to withstand a disturbance to the system are critically important in maintaining the security of supply to NSW customers. A high level of reliability implies the need for a robust transmission system. The capital cost of this system is balanced by:

- Avoiding the large cost to the community of widespread shortages of supply;
- Providing flexibility in the choice of economical generating patterns;
- Allowing reduced maintenance costs through easier access to equipment; and
- Minimising electrical losses which also provides benefit to the environment.

The planning of the main system must take into account the risk of forced outages of a transmission element coinciding with adverse conditions of load and generation dispatch. Two levels of load forecast (summer and winter) are considered, as follows.

Loads at or exceeding a one in two year probability of occurrence (50% POE)

The system will be able to withstand a single contingency under all reasonably probable patterns of generation dispatch or interconnection power flow. In this context, a single contingency is defined as the forced outage of a single transmission circuit, generating unit, transformer, reactive plant or a busbar section.

Provision is made for a prior outage (following failure) of a single item of reactive plant.

Further, the system will be able to be secured by re-dispatching generation (AEMO action), without the need for pre-emptive shedding (interruption) of load, so as to withstand the impact of a second contingency.

Loads at or exceeding a one in ten year probability of occurrence (10% POE)

The system will be able to withstand a single contingency under a limited set of patterns of generation dispatch or interconnection power flow.

Further, the system will be able to be secured by re-dispatching generation (AEMO action), without the need for pre-emptive load shedding, so as to withstand the impact of a second contingency.

These criteria do not apply to radial sections of the main system.

The patterns of generation applied to the 50% POE load level cover patterns that are expected to have a relatively high probability of occurrence, based on the historical performance of the NEM and modelling of the NEM generation sources into the future. The limited set of patterns of generation applied to the 10% probability of exceedance load level cover two major power flow characteristics that occur in NSW. The first power flow characteristic involves high output from base-load generation sources throughout NSW and high import to NSW from QLD. The second power flow characteristic involves high import to NSW from VIC, southern and south west NSW generation coupled with high output from the NSW base-load generators.

Under all conditions there is a need to achieve adequate voltage control capability. We have traditionally assumed that all online generators can provide reactive power support within their rated capability. However, we align with other utilities in relying only on the reactive capability given by performance standards. Reactive support beyond the performance standards may need to be procured under network support arrangements.

A further consideration is the provision of sufficient capability in the system to allow components to be maintained in accordance with our asset management strategies.

Supply in NSW is heavily dependent on base load coal fired generation in the Hunter Valley, the western area and Central Coast. These areas are interconnected with the load centres via numerous single and double circuit lines. In planning the NSW system, taking into account AEMO's operational approach to the system, there is a need to consider the risk and impact of overlapping outages of circuits under high probability patterns of load and generation.

The analysis of network adequacy must take into account the probable load patterns, typical dispatch of generators and loads, the availability characteristics of generators (as influenced by maintenance and forced outages), energy limitations and other factors relevant to each case.

Options to address an emerging inability to meet all connection point loads would be considered with allowance for the lead time for a network augmentation solution.

Before this time, consideration may be given to the costs involved in re-dispatch in the energy and ancillary services markets to manage single contingencies. In situations where these costs appear to exceed the costs of a network augmentation, this will be brought to the attention of network load customers for consideration. We may then initiate the development of a network or non-network solution through a consultation process.

70 TransGrid lines have automatic systems to return them to service (reclose them) following a fault.

Relationship with inter-regional planning

We monitor the occurrence of constraints in the main transmission system that affects generator dispatch. Our planning therefore considers the scope for network augmentations to reduce constraints that may satisfy the RIT-T.

Under the provisions of the NER, a Region may be created where constraints to generator dispatch are predicted to occur with reasonable frequency when the network is operated in the 'system normal' (all significant elements in service) condition. The creation of a Region does not consider the consequences to load connection points if there should be a network contingency.

The capacity of interconnectors that is applied in the market dispatch is the short-time capacity determined by the ability to maintain secure operation in the system normal state in anticipation of a single contingency. The operation of the interconnector at this capacity must be supported by appropriate ancillary services. AEMO does not operate on the basis that the contingency may be sustained but - considers the impact of a prolonged plant outage.

As a consequence, it is probable that for parts of the network that are critical to the supply of loads, we would initiate augmentation, if needed, to meet the new NSW Electricity Transmission Reliability and Performance Standard 2017 before the creation of a new Region.

The development of interconnectors between regions is undertaken where the augmentation satisfies the RIT-T. The planning of interconnections is undertaken in consultation with the jurisdictional planning bodies of the other states.

It is not planned to maintain the capability of an interconnector where relevant network developments would not satisfy the RIT-T.

Networks supplied from the main transmission network

Some parts of the network are primarily concerned with supply to local loads and are not significantly impacted by the dispatch of generation (although they may contain embedded generators). The loss of a transmission element within these networks does not have to be considered by AEMO in determining network constraints, although ancillary services may need to be provided to cover load rejection in the event of a single contingency.

Supply to major load areas and sensitive loads

The NSW system contains six major load areas: Northern; Newcastle and Central Coast; Greater Sydney; Central; Southern; and South Western NSW.

Some of these load areas, including individual smelters, are supplied by a limited number of circuits, some of which may share double circuit line sections. It is strategically necessary to ensure that significant individual loads and load areas are not exposed to loss of supply in the event of multiple circuit failures for an extended duration of time.

As a consequence, it is necessary to assess the impact of contingency levels that exceed the specified level of redundancy and expected unserved energy for the respective network nodes.

Outages of network elements for planned maintenance must also be considered. Generally this requires 75% of the maximum load to be supplied during the outage. While every effort is made to secure supplies in the event of a further outage, this may not be always possible. In this case attention is directed to minimising the duration of the plant outage.

Urban and suburban areas

Generally, urban and suburban networks are characterised by a high load density served by high capacity underground cables and relatively short transmission lines. The connection points to the network are usually the low voltage (132 kV) busbars of 330 kV substations. There may be multiple connection points and significant capability on the part of the DNSP to transfer load between connection points, either permanently or to relieve short-time loadings on network elements after a contingency.

The focus of joint planning with DNSPs is the capability of the meshed 330/132 kV system and the capability of the existing connection points to meet expected maximum loadings. Joint planning addresses the need for augmentation to the meshed 330/132 kV system and the connection point capacity or to provide a new connection point where this is the most economic overall solution.

Consistent with good international practice, supply to high-density urban and central business districts is given special consideration. For example, the inner Sydney metropolitan network serves a large and important part of the State load. Supply to this area is largely via 330 kV and 132 kV underground cable network. The 330 kV cables are part of our network and the 132 kV cables are part of Ausgrid's network.

The criterion applied to the Inner Sydney area is consistent with that applied in the electricity supply to major cities throughout the world. Most countries use an N–2 criterion, whereas some countries apply an N–1 criterion with some selected N–2 contingencies that commonly include two cables sharing the one trench or a double circuit line. This is similar to the approach adopted previously in NSW. Using the probabilistic approach specified under the NSW Electricity Transmission Reliability Standard 2017, supply to the Inner Sydney load is required to be designed for Category 3 level of redundancy[71] and maximum unserved energy allowance corresponding to 0.6 minute per year at average demand[72].

Also, it should be noted that the reliability criteria (redundancy level and unserved energy allowance per year) at bulk supply points outside the Inner Sydney area are less onerous than those for Inner Sydney area.

Outages of network elements for planned maintenance must are also considered. Generally this requires 75% of the maximum load to be supplied during an outage.

While every effort is made to secure supplies in the event of a further outage, this may not always be possible. In this case attention is directed to minimising the duration of the outage.

71 NSW Electricity Transmission Reliability and Performance Standard 2017 Clause 3
72 NSW Electricity Transmission Reliability and Performance Standard 2017 Clause 4

Non-urban areas

Generally, these areas are characterised by lower load densities and, generally, lower reliability requirements than urban systems. The areas are sometimes supplied by relatively long, often radial, transmission systems. Connection points in those areas are either on 132 kV lines or on the low voltage busbars of 132 kV substations. Although there may be multiple connection points to a DNSP, they are often far apart and there may be little capacity for power transfer between them. Frequently supply limitations may apply to the combined capacity of several supply points together.

The focus of joint planning with DNSPs usually relates to:

- Augmentation of connection point capacity;
- Duplication of radial supplies;
- Extension of the 132 kV system to reinforce or replace existing lower voltage systems and to reduce losses; and
- Development of a higher voltage system to provide major augmentations and to reduce network losses.

Supply to one or more connection points is sometimes considered to require augmentation when the transmission network supplying the load does not provide the specified redundancy level or the probability of unserved energy (i.e function of network failure rate, restoration duration and average load) at the end of the planning horizon exceeds the specified reliability criteria.

As a result of the application of the criteria, some radial parts of the 330 kV and 220 kV network are not able to withstand the forced outage of a single circuit line at time of maximum load, and in these cases provision is made for under-voltage load shedding.

Provision is also required for the maintenance of the network. Additional redundancy in the network is required where maintenance cannot be scheduled without causing load restrictions or an unacceptable level of risk to the security of supply.

Transformer augmentation

In considering the augmentation of transformers, appropriate allowance is made for the transformer cyclic rating[73] and the practicality of load transfers between connection points. Allowance is made for the outage of a single transformer (or single-phase unit) or a transmission line that supports the load carried by the transformer.

Provision is also required for the maintenance of transformers. This has become a critical issue at a number of sites in NSW where there are multiple transformers in service. To enable maintenance to be carried out, additional transformer capacity or a means of transferring load to other supply points via the underlying lower voltage network may be required.

Consideration of low probability events

Although there is a low probability that supply to loads may need to be interrupted as a result of system disturbances, no power system can be guaranteed to deliver a firm capability 100% of the time, particularly when subjected to disturbances that are severe or widespread. It is also possible that extreme loads, above the level allowed for in planning, can occur, usually under extreme weather conditions.

The NSW network contains numerous lines of double circuit construction and, whilst the probability of overlapping outages of both circuits of a line is very low, the consequences could be widespread supply disturbances.

Thus there is a potential for low probability events to cause localised or widespread disruption to the power system. These events can include:

- Loss of several transmission lines within a single corridor, as may occur during bushfires;
- Loss of a number of cables sharing a common trench;
- Loss of more than one section of busbar within a substation, possibly following a major plant failure;
- Loss of a number of generating units; or
- Occurrence of three-phase faults[74], or faults with delayed clearing.

In our network, appropriate facilities and mechanisms are put in place to minimise the probability of such events and to lessen their impact. The decision process considers the underlying economics of facilities or corrective actions, taking account of the low probability of the occurrence of extreme events.

We take measures, where practicable, to minimise the impact of disturbances to the power system by implementing power system control systems at minimal cost in accordance with the NER.

73 Transformer nominal ratings are based on them carrying a constant load. However, loads are often cyclic (they vary throughout the day). In these cases transformers may be able to carry more than their nominal rating for a short period around the time of the maximum load as they are loaded less heavily before and after that period. A cyclic loading takes this into account.
74 Alternating current power systems generally have three phases. Faults on those systems can involve one, two or all three of those phases. Faults involving three phases are generally the most onerous.

A3.3 Protection requirements

Basic protection requirements are included in the NER. The NER requires that protection systems be installed so that any fault can be detected by at least two fully independent protection systems. Backup protection is provided against circuit breaker failure. Provision is also made for detecting high resistance earth faults.

Required protection clearance times are specified by the NER and determined by stability considerations as well as the characteristics of modern power system equipment. Where special protection facilities or equipment are required for high-speed fault clearance, they are justified on either NER compliance or a benefit/cost basis.

All modern distance protection systems on the main network include the facility for power swing blocking (PSB). PSB is utilised to control the impact of a disturbance that can cause synchronous instability. At the moment PSB is not enabled, except at locations where demonstrated advantages apply. This feature has become increasingly more important as the interconnected system is developed and extended.

A3.4 Transient stability

In accordance with the NER, transient stability is assessed on the basis of the angular swings following a solid fault on one circuit at the most critical location that is cleared by the faster of the two protections (with intertrips assumed in service where installed). The determination of the transient stability capability of the main grid is undertaken using software that has been calibrated against commercially available system dynamic analysis software.

To assess this at the main system level a two phase-to-ground fault is applied. On 132 kV systems, which are to be augmented, a three-phase fault is applied.

Recognition of the potential impact of a three-phase fault at the main system level is made by instituting maintenance and operating precautions to minimise the risk of such a fault.

Where transient stability is a factor in the development of the main network, preference is given to the application of advanced control of the power system or high-speed protection systems, before consideration is given to the installation of high capital cost plant.

A3.5 Steady state stability

The requirements for the control of steady state stability are included in the NER. For planning purposes, steady state stability (or system damping) is considered adequate under any given operating condition if, after the most critical credible contingency, simulations indicate that the halving time of the least damped electromechanical mode of oscillation is not more than five seconds.

The determination of the steady state stability performance of the system is undertaken using software that has been calibrated against commercially available software and from data derived from the monitoring of system behaviour.

In planning the network, maximum use is made of existing plant, through the optimum adjustment of plant control system settings before consideration is given to the installation of high capital cost plant.

A3.6 Line and equipment thermal ratings

Line thermal ratings have often traditionally been based on a fixed continuous rating and fixed short-time ratings. We apply line ratings, which are dependent on the weather conditions and line design parameters. A normal rating, contingency rating (30-minute rating) and short-time emergency ratings have been developed. Typically, the short-time ratings are based on a load duration of 15 minutes, although the duration can be adjusted to suit the particular load pattern to which the line is expected to be exposed. The duration and level of loading takes into account any requirements for re-dispatch of generation or load control.

Ambient condition monitors have been installed on a number of transmission lines to enable the application of real-time line conductor ratings in the generation dispatch systems.

Transformers are rated according to their specification. Provision is also made for use of the short-time capability of the transformers during the outage of a parallel transformer or transmission line.

The 330 kV cables are rated according to the manufacturer's recommendations and have been checked against an appropriate thermal model of the cable.

The rating of line terminal equipment is based on the manufacturers' advice.

A3.7 Reactive support and voltage stability

It is necessary to maintain voltage stability, with voltages within acceptable levels, following the loss of a single element in the power system at times of maximum system loading. The single element includes a generator, a single transmission circuit, a cable and single items of reactive support plant.

To cover fluctuations in system operating conditions, uncertainties of load levels, measurement errors and errors in the setting of control operating points, it is necessary to maintain a margin from operating points that may result in a loss of voltage control. A reactive power margin is maintained over the point of voltage instability or alternatively a margin is maintained with respect to the power transfer compared to the maximum feasible power transfer.

The system voltage profile is set to standard levels during generator dispatch to minimise the need for post-contingency reactive power support.

Reactive power plant generally has a low cost relative to major transmission lines, and the incremental cost of providing additional capacity in a shunt capacitor bank can be relatively low. Such plant can also have a very high benefit/cost ratio and therefore the timing of reactive plant installations is generally less sensitive to changes in load growth than the timing of other network augmentations. Even so, the aim is to make maximum use of existing reactive sources before new installations are considered.

We have traditionally assumed that all online generators can provide reactive power support within their rated capability. However, now the assumption is aligned with other utilities in relying only on the reactive capability given by agreed performance standards of the generator. Reactive support beyond the performance standards may need to be procured under network support arrangements.

Reactive power plant is installed to support planned power flows up to the capability defined by limit equations, and is often the critical factor determining network capability. On the main network, allowance is made for the unavailability of a single major source of reactive power support in the critical area affected at times of high load, but not at the maximum load level.

It is also necessary to maintain control of the supply voltage to the connected loads under minimum load conditions.

The factors that determine the need for reactive plant installations are:

- In general it has proven prudent and economic to limit the voltage change between the pre- and post-contingency operating conditions;
- It has also proven prudent, in general, and economic to ensure that the post-contingency operating voltage at major 330 kV busbars lies above a lower limit;
- The reactive margin from the point of voltage collapse is maintained to be greater than a minimum acceptable level;
- A margin between the power transmitted and the maximum feasible power transmission is maintained; and
- At times of light system load, it is essential to ensure that voltages can be maintained within the system highest voltage limits of equipment.

Following forced outages, relatively large voltage changes are accepted at some locations on the main network, and agreed with customers, providing voltage stability is not placed at risk. These voltage changes can approach, and in certain cases, exceed 10% at maximum load.

On some sections of the network, the possibility of loss of load due to depressed voltages following a contingency is also accepted. However, there is a preference to install load shedding initiated by under-voltage so that the disconnection of load occurs in a controlled manner.

When determining the allowable rating of switched reactive plant, the requirements of the NER are observed.

A3.8 Transmission line voltage and conductor sizes determined by economic considerations

Consideration is given to the selection of line design voltages within the standard nominal 132 kV, 220 kV, 275 kV, 330 kV and 500 kV range, taking due account of transformation costs.

Minimum conductor sizes are governed by losses, radio interference and field strength considerations.

We strive to reduce the overall cost of energy and network services by the economic selection of line conductor size. The actual losses that occur are governed by generation dispatch in the market.

For a line whose design is governed by economic loading limits, the conductor size is determined by a rigorous consideration of capital cost versus loss costs.

Hence the impact of the development on generator and load marginal loss factors in the market is considered. For other lines, the rating requirements will determine the conductor requirements.

Double circuit lines are built in place of two single circuit lines where this is considered to be both economic and is able to provide adequate reliability. Consideration is given to the impact of a double circuit line failure, both over relatively short terms and for extended durations. This means that supply to a relatively large load may require single rather than double circuit transmission line construction where this is environmentally acceptable.

In areas prone to bushfire, any parallel single circuit lines are preferably routed well apart to avoid the risk of simultaneous outage during a bushfire event.

A3.9 Short-circuit rating requirements

Substation high voltage equipment is designed to withstand the maximum expected short circuit duty in accordance with the applicable Australian Standard.

Operating constraints are enforced to ensure equipment is not exposed to fault duties beyond the plant ratings.

In general, the short circuit capability of all of the plant at a site would be designed to match or exceed the maximum short circuit duty at the relevant busbar. In order to achieve cost efficiencies when augmenting an existing substation, the maximum possible short circuit duty on individual substation components may be calculated and applied in order to establish the adequacy of the equipment.

Short circuit duty calculations are based on the following assumptions:

- All main network generators that are capable of operating, as set out in connection agreements are assumed to be in service;
- All generating units that are embedded in distribution networks are assumed to be in service;
- The maximum fault contribution from interstate interconnections is assumed;
- The worst-case pre-fault power flow conditions are assumed;
- Normally open connections are treated as open;
- Networks are modelled in full;
- Motor load contributions are not modelled at load substations; and
- Generators are modelled as a constant voltage behind sub-transient reactance.

At power station switchyards, allowance is made for the contribution of the motor component of loads. Further analysis of the impact of the motor component of loads is performed and this is done to assess the need to include such contributions when assessing the adequacy of the rating of load substation equipment.

A3.10 Substation configurations

Substation configurations are adopted that provide acceptable reliability at minimum cost, consistent with the overall reliability of the transmission network. In determining a switching arrangement, consideration is also given to:

- Site constraints;
- Reliability expectations with respect to connected loads and generators;
- The physical location of 'incoming' and 'outgoing' circuits;
- Maintenance requirements;
- Operating requirements; and
- Transformer arrangements.

The following configurations are being applied:

- Single busbar;
- Double busbar;
- Multiple element mesh; and
- Breaker-and-a-half.

In general, at main system locations, a mesh or breaker-and-a-half arrangement are the preferred minimum-requirement standard configurations.

Where necessary, the expected reliability performance of potential substation configurations can be compared using equipment reliability parameters derived from local and international data.

The forced outage of a single busbar zone is generally provided for. Under this condition, the main network is planned to have adequate capability although loss of load may eventuate. In general, the forced outage of a single busbar zone should not result in the outage of any baseload generating unit.

Where appropriate, a 330 kV bus section breaker would ordinarily be provided to segregate 'incoming' lines when a second 'incoming' 330 kV line is connected to the substation.

A 132 kV bus section circuit breaker would generally be considered necessary when the maximum load supplied via that busbar exceeds 120 MW. A bus section breaker is generally provided on the low voltage busbar of 132 kV substations when supply to a particular location or area is taken over more than two low voltage feeders.

A3.11 Autoreclosure

As most line faults are of a transient nature, all of our overhead transmission lines are equipped with autoreclose facilities. Slow speed three-pole reclosure is applied to most overhead circuits. On the remaining overhead circuits, under special circumstances, high-speed single-pole autoreclosing may be applied.

For public safety reasons, reclosure is not applied to underground cables.

Autoreclose is inhibited following the operation of breaker-fail protection.

A3.12 Power system control and communication

In the design of the network and its operation to designed power transfer levels, reliance is generally placed on the provision of some of the following control facilities:

- Automatic excitation control on generators;
- Power system stabilisers on generators and SVCs;
- Load drop compensation on generators and transformers;
- Supervisory control over main network circuit breakers;
- Under-frequency load shedding;
- Under-voltage load shedding;
- Under and over-voltage initiation of reactive plant switching;
- High speed transformer tap changing;
- Network connection control;
- Check and voltage block synchronisation;
- Control of reactive output from SVCs; and
- Remidial Action Schemes (RAS).

The following communication, monitoring and indication facilities are also provided where appropriate:

- Network wide SCADA and Energy Management;
- System (EMS);
- Telecommunications and data links;
- Mobile radio;
- Fault locators and disturbance monitors;
- Protection signalling; and
- Load monitors.

Protection signalling and communication is provided over a range of media including pilot wire, power line carrier, microwave links and, increasingly, optical fibres in overhead earthwires.

A3.13 Scenario planning

Scenario planning assesses network capacity, based on the factors described above, for a number of NEM load and generation scenarios. The process entails:

1. Identification of possible future load growth scenarios. These are developed based on TransGrid's NSW region forecasts along with consideration of respective DNSPs' bulk supply point load forecasts and directly connected customer demand outlook. It considers key data for each scenario to prepare load forecasts for NSW. These are published in the TAPR. The forecast can also incorporate specific possible local developments such as the establishment of new loads or the expansion or closure of existing industrial loads.
2. Development of a number of generation scenarios for each load growth scenario. These generation scenarios relate to the development of new generators and utilisation of existing generators, and considers expected or possible future retirements. This is generally undertaken by a specialist electricity market modelling consultant, using their knowledge of relevant factors, including:
   - Generation costs;
   - Impacts of government policies;
   - Impacts of energy related developments such as gas pipeline projects;
3. Modelling of the NEM for load and generation scenarios to quantify factors which affect network performance, including:
   - Generation from individual power stations;
   - Interconnector flows;
4. Modelling of network performance for the load and generation scenarios utilising the data from market modelling.

The resulting set of scenarios is then assessed over the planning horizon to establish the adequacy of the system and to assess network and non-network augmentation options.

The planning scenarios developed by TransGrid take into account AEMO's outlook stated in its latest ESOO and the scenarios considered in the ISP.

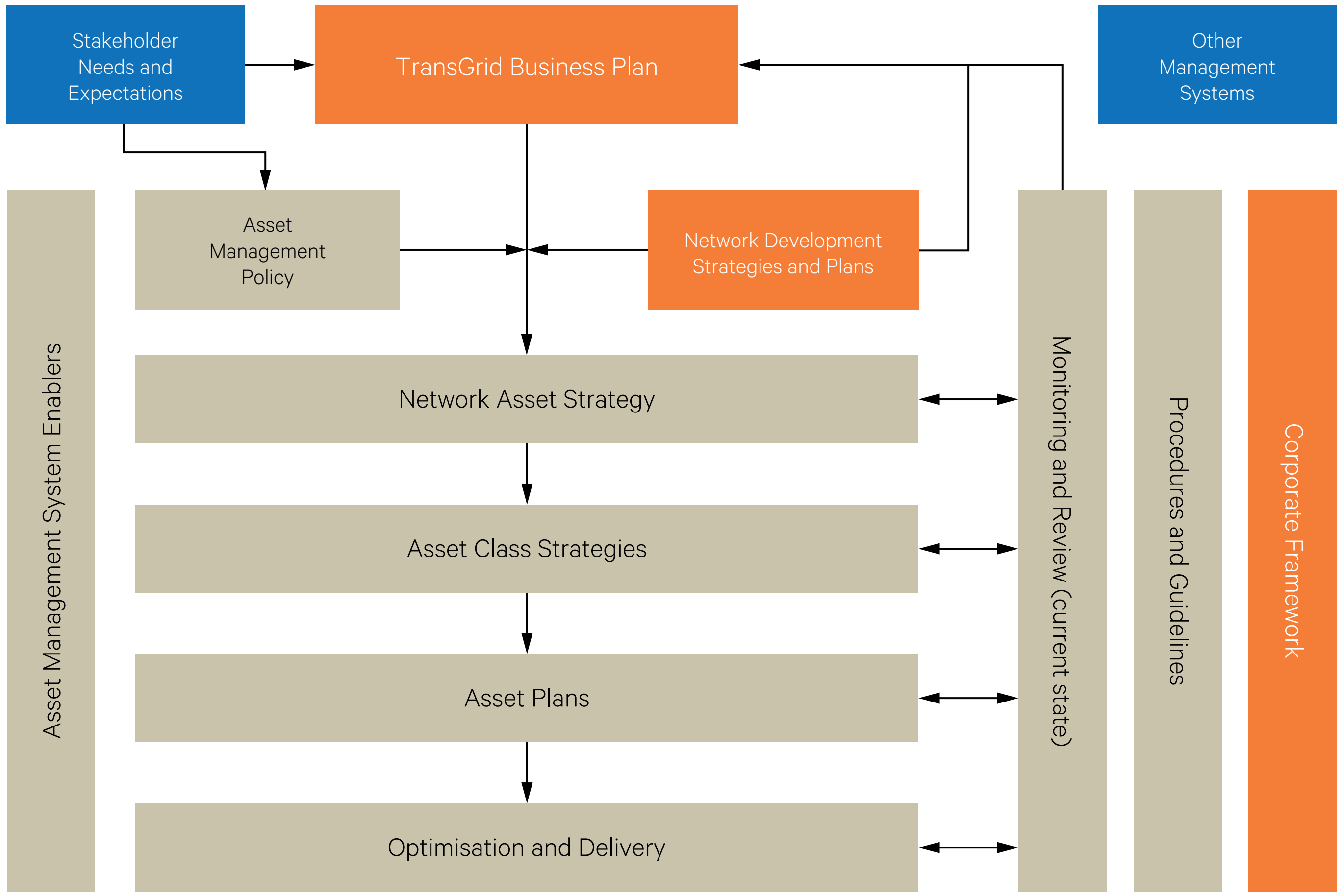
A3.14 Asset management approach

Our Asset Management System (AMS) manages our transmission network assets over their entire lifecycle. The AMS covers management of assets from the planning stage through the build/acquire, operate, maintain, renew and decommissioning stages. Our approach to asset management encompasses our jurisdictional requirements and obligations to meet the service level requirements of our customers, consumers and other stakeholders. Development of our asset renewal program involves assessment of the most economic combination of replacement and refurbishment options.

The AMS has been developed in accordance with the principles of ISO 55001, the international standard for asset management. TransGrid has obtained external certification that this system meets or exceeds the requirements of ISO 55001.

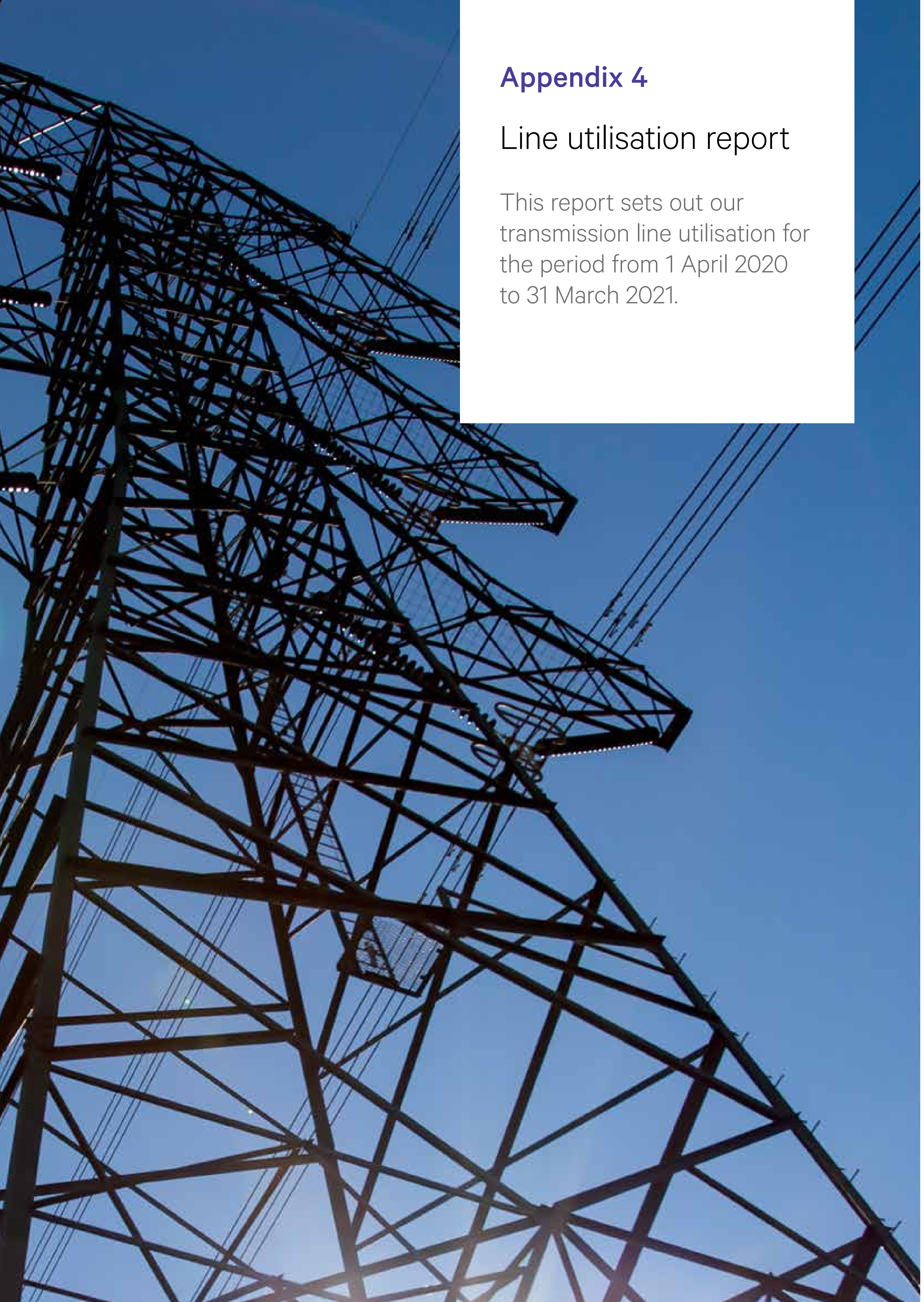
The following figure illustrates our AMS structure under ISO 55001.

Figure A3.2: Asset Management System (AMS)



The decision-making processes within our AMS have improved through the development of a quantified methodology for assessing risk. This risk assessment methodology combines an understanding of the failure behaviour of an asset (the likelihood), and the expected consequences of failure (the consequence), to value the risk associated with an asset in monetary terms.

This risk management approach ensures that we are managing our significant risks as so far as practicable, or where this is not possible as low as reasonably practicable. The processes for managing key safety risks under this framework are described in our Electricity Network Safety Management System.



Appendix 4

Line utilisation report

This report sets out our transmission line utilisation for the period from 1 April 2020 to 31 March 2021.

A4.1 Line utilisation report

The line loading information from 1 April 2020 to 31 March 2021 was obtained from AEMO's Operations and Planning Data Management System (OPDMS). This system produces half hourly system load flow models (snapshots) of the NEM.

For each half-hour period, the utilisation (loading) of each line was calculated as a proportion of the relevant rating.

The highest values of these proportions are reported here.

The utilisation of each line was calculated based on two conditions:

1. With all network elements in service, referred to as the 'N utilisation'. These utilisation figures are based on normal line ratings; and
2. With the most critical credible contingency (usually an outage of another line in the area), referred to as the 'N–1 utilisation'. These utilisation figures are based on the line contingency ratings.

The N utilisation and N–1 utilisation of the transmission lines in the NSW transmission network are shown in **Figures A4.2–9**. For each line, the utilisations are shown in the box placed adjacent to the line. The box shows:

A. The transmission line number;

B. The maximum N utilisation of the transmission line;

C. The maximum N–1 utilisation of the transmission line; and

D. The identity of the line that creates the critical contingency in the event of an outage.

The box layout is shown in **Figure A4.1**.

Figure A4.1: Key to interpreting the information shown in Figures A4.2 to A4.9

A – Line number:B – Maximum N Utilisation % C – Maximum N–1 Utilisation % [D – Line number out for N–1]

In some situations, the N–1 utilisation has been estimated to be more than 100 per cent. These situations could be because of:

- A higher level of line loading being allowed, considering the operational line overloading control schemes, runback schemes available for managing the line loadings, and generation re-dispatch capability by AEMO; and
- The predicted dispatch conditions that change over the five-minute dispatch period, causing the line loadings to increase above the predicted values.

Figure A4.2: TransGrid N and N–1 line utilisations – Sydney and Newcastle

Figure A4.3: TransGrid N and N–1 line utilisations – North East NSW and Northern NSW

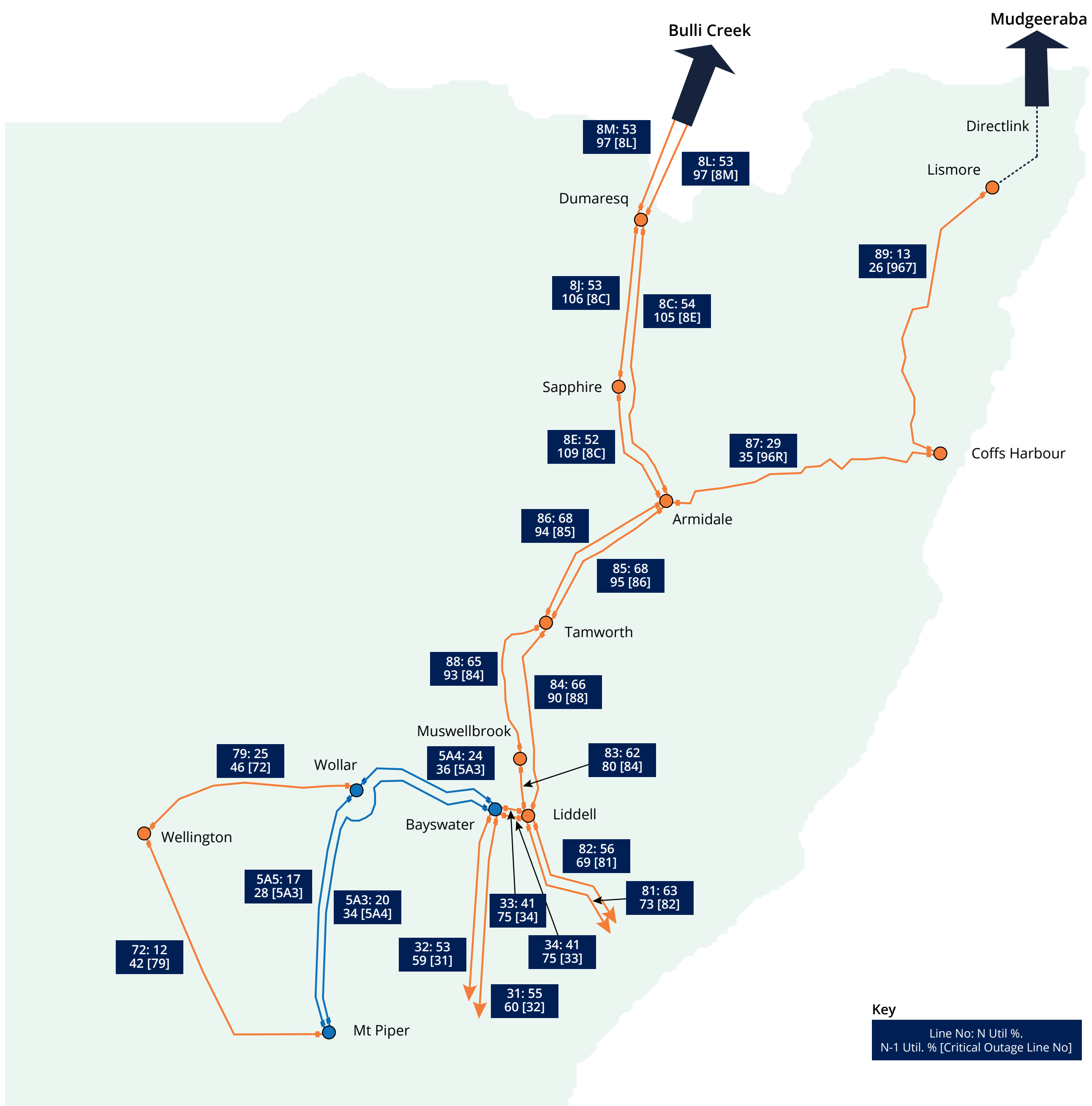


Figure A4.4: TransGrid N and N-1 line utilisations – South and South East

Figure A4.5: TransGrid N and N-1 line utilisations – Far West

Figure A4.6: TransGrid N and N–1 line utilisations – North Coast and North West 132 kV System

Figure A4.7: TransGrid N and N–1 line utilisations – Central West

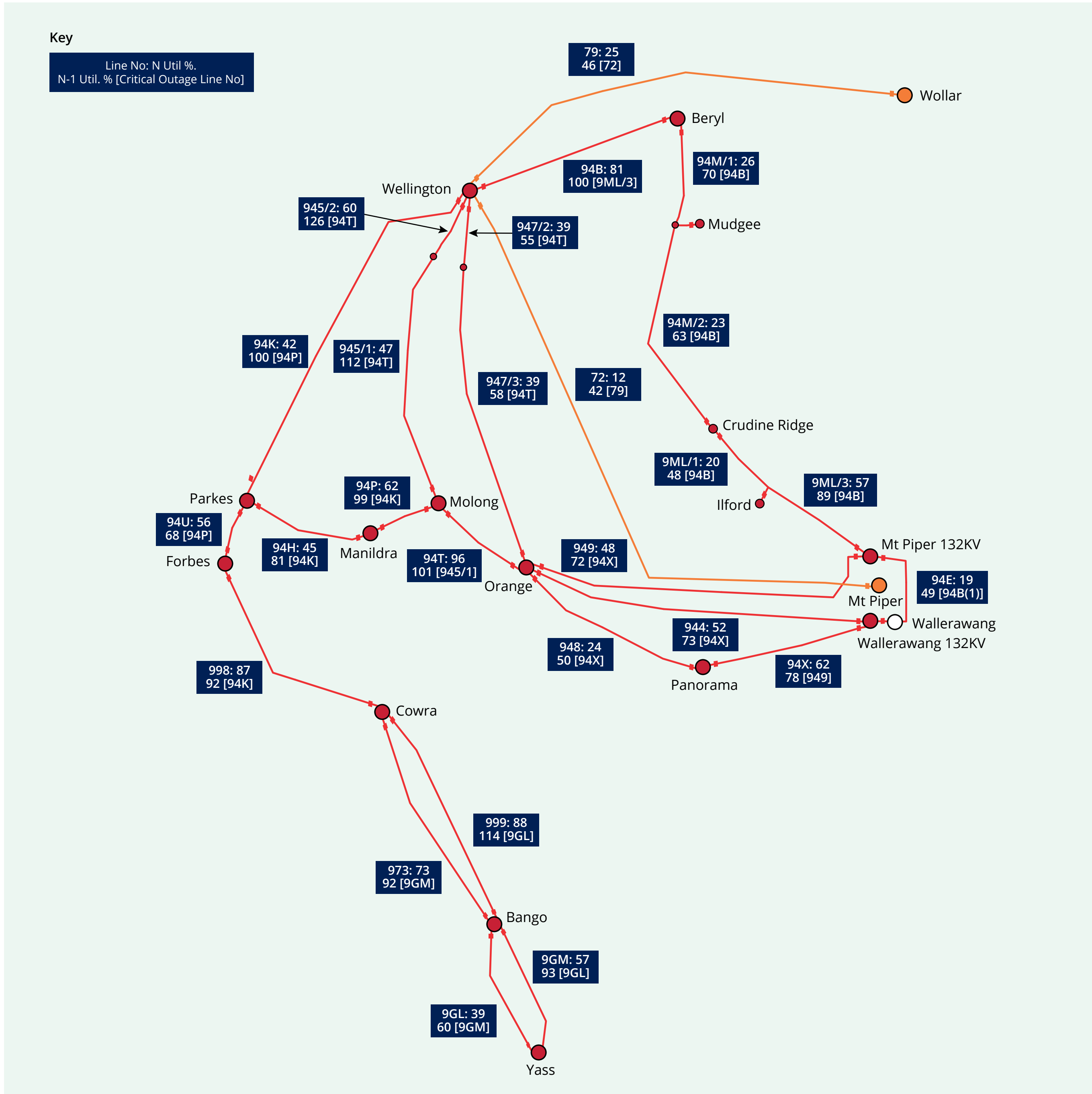


Figure A4.8: TransGrid N and N–1 line utilisations – South East

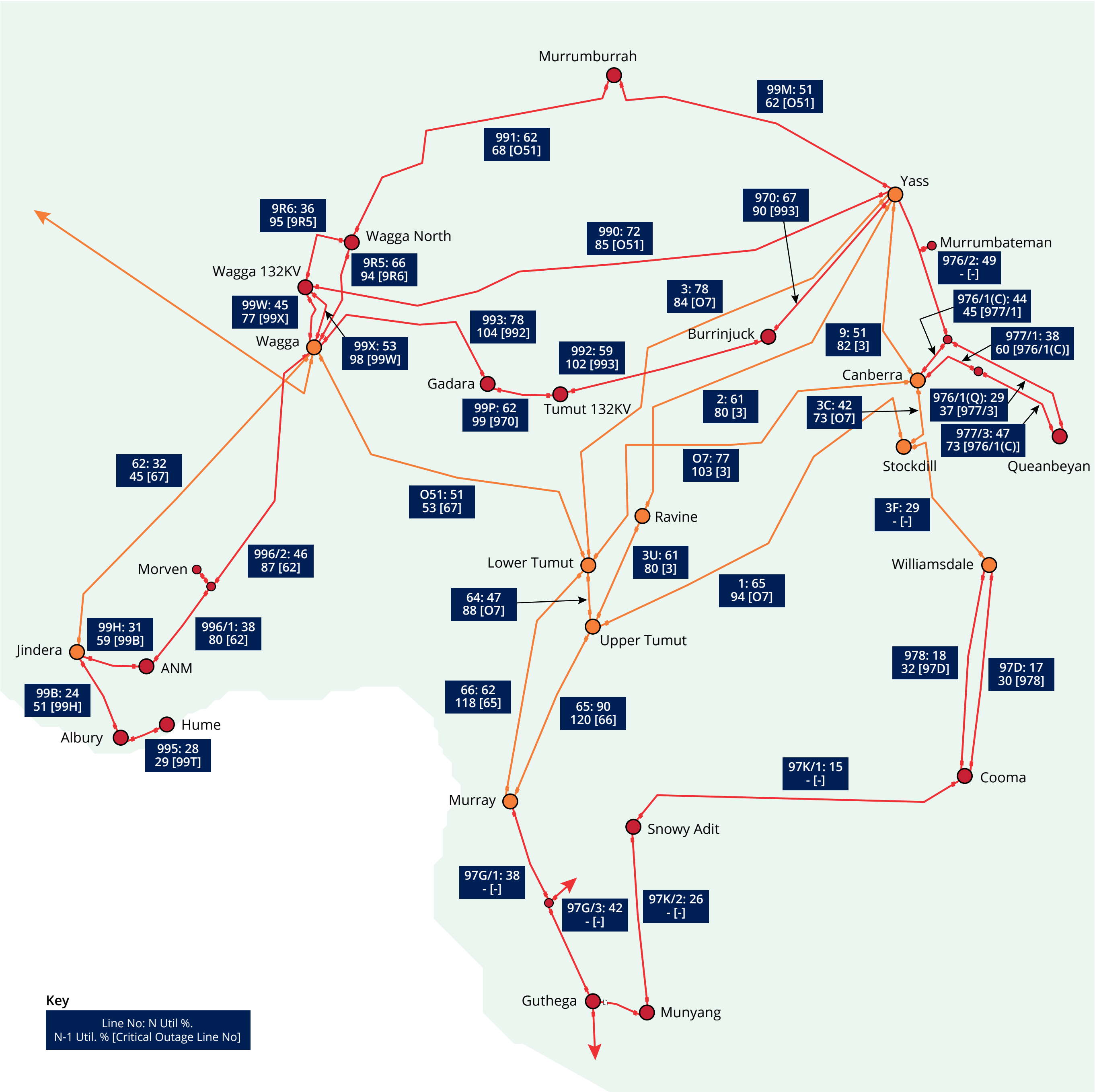
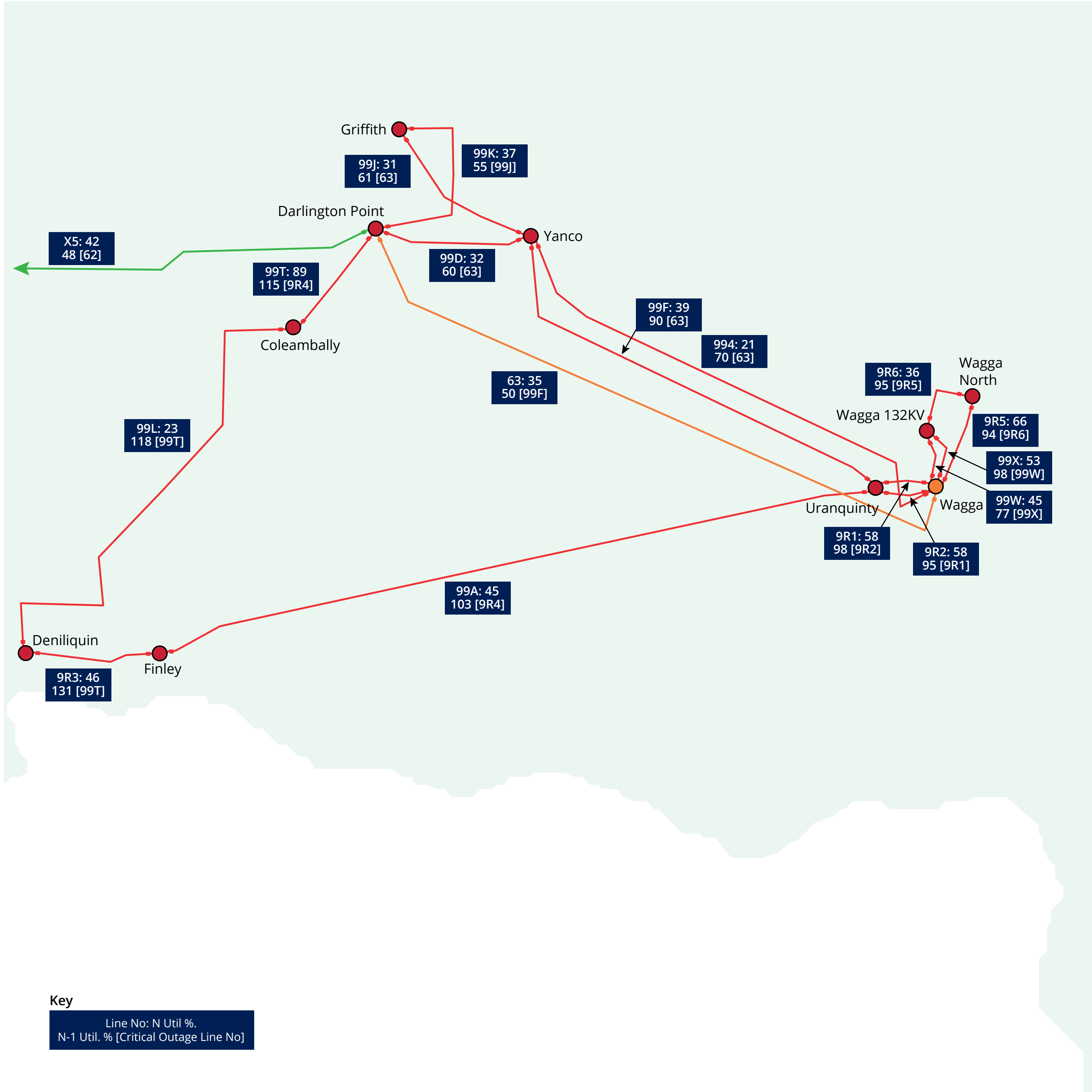


Figure A4.9: TransGrid N and N–1 line utilisations – South West



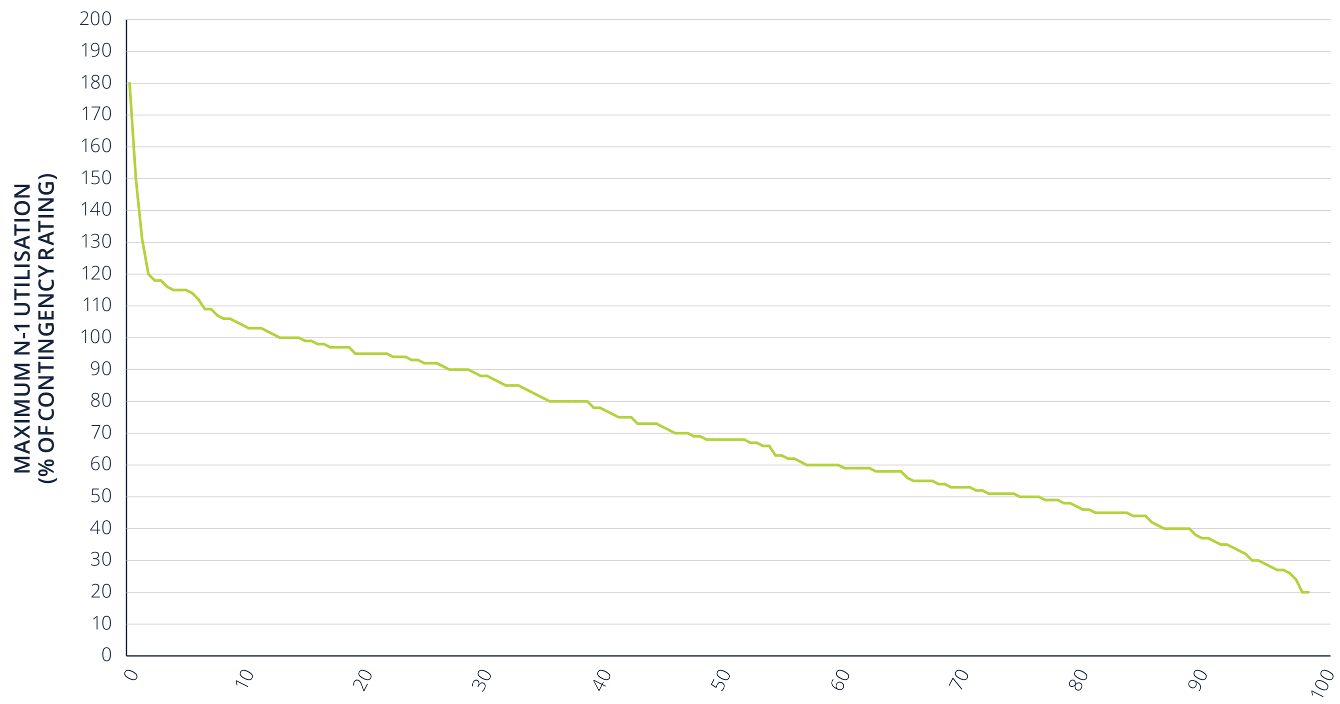
Summary of the N–1 utilisation of the transmission lines in the TransGrid's network

The distribution of the N-1 utilisation of the transmission lines across our network is shown in **Figure A4.10**.

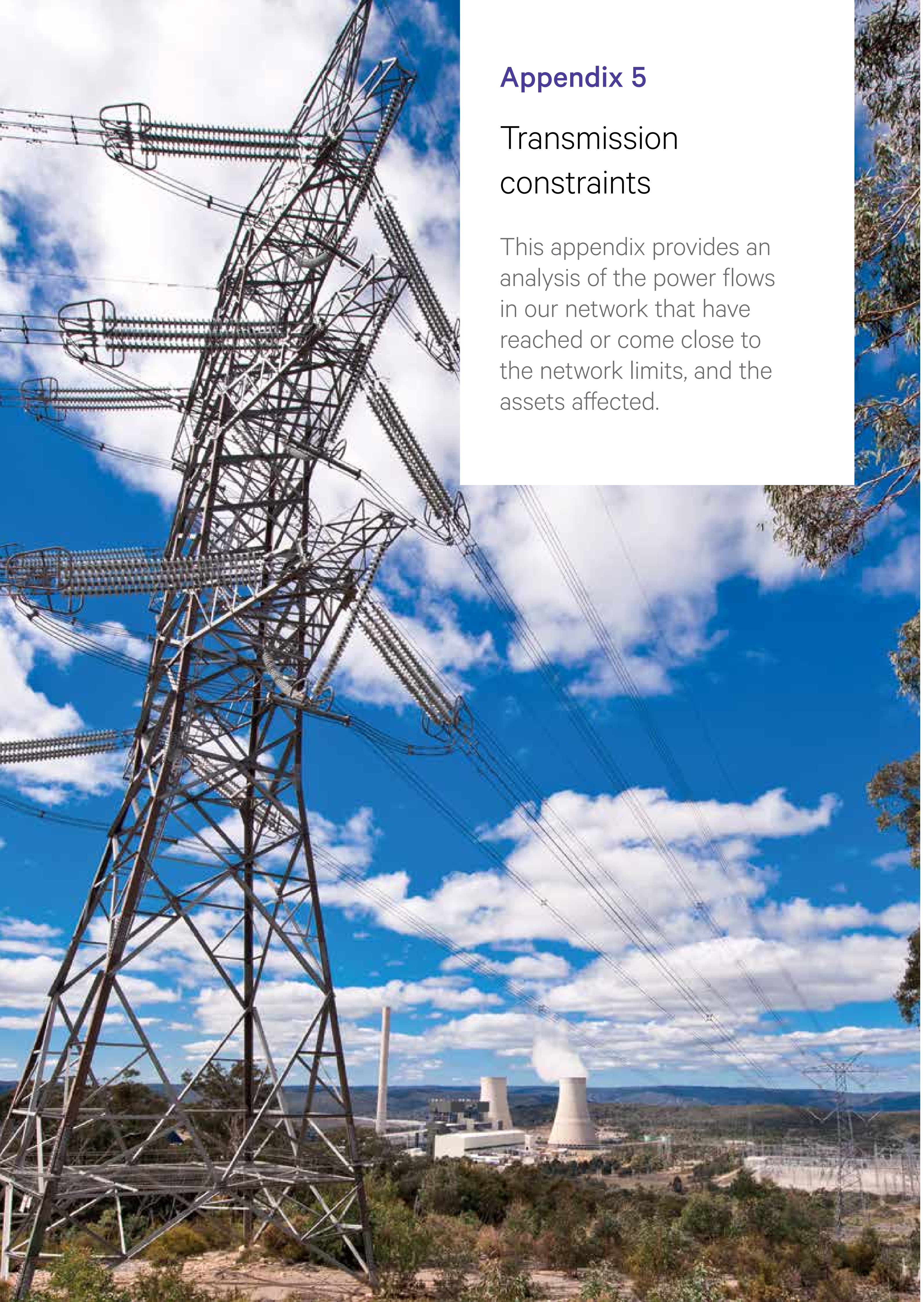
The distribution shows that approximately 14 per cent of the transmission lines in the network are utilised at more than their installed maximum capacity and over half of the lines are utilised at more than 68 per cent of their installed capacity.

The distribution of the N–1 line utilisations reflects at least 40 years of planning history of the transmission network. It is considered to be typical of a well-planned network where various parts of the network are well-established, while other parts have had recent step augmentations that will be further utilised in future years.

Figure A4.10: Distribution of TransGrid N–1 utilisations (1 April 2020-31 March 2021)



Scarred trees tell us where Aboriginal people used to live, what they may have used the tree for and also provide Aboriginal people today with a link to their culture and past.



Appendix 5

Transmission constraints

This appendix provides an analysis of the power flows in our network that have reached or come close to the network limits, and the assets affected.

A5.1 Introduction

This appendix describes an analysis of how close the flows in our network are to its capacity limits. It identifies the transmission elements where flows have been at, or close to, the limits.

Capacity could be limited due to the power flows reaching:

- The maximum rating of a single transmission element, such as a transmission line or a transformer;
- The combined capacity of a group of transmission elements, such as several parallel transmission lines constituting inter regional links; and
- The limits set by system wide considerations such as voltage, transient or oscillatory stability.

TransGrid provides the capability of its transmission network to AEMO. AEMO manages the power flows in the transmission network to be within the capability of the declared limits of the individual assets or the capability of the transmission system. AEMO does so by automatically adjusting the quantity of generation dispatched, so that the transmission flows will be maintained under the prevailing operating conditions, including the flows to be expected under credible unplanned outages.

The optimal generation dispatch, the dispatch which minimises total cost while ensuring the capability limits of the transmission system are not violated, is determined using the National Electricity Market Dispatch Engine (NEMDE). The capability limits are included within NEMDE as mathematical equations, which are known as the 'Constraint Equations'. Each constraint equation has a unique identifier, and contains information including the capability limit and the factors which describe or determine the limiting power flows, such as power flow in a transmission line or generator power outputs, which contribute to the limiting power flow.

The constraints reported here cover the transmission system capability limitation experienced during the period 1 March 2020 to 28 February 2021.

A5.2 Transmission system performance – Binding duration

Table A5.1 summarises the top 20 constraints where higher cost generation may have been dispatched because some transmission elements or parts of the transmission network have reached their maximum capability. The table shows the constraint identifier, its description, type of limitation addressed by the constraint equation, and length of the time period where the transmission element, or the part of the transmission system, was operated at its maximum capability for the 12 month period (1 March 2020 – 28 February 2021).

Table A5.1: Constraints operating at the capability limit

Rank	Constraint ID	Total duration (dd:hh:mm)	Type	Impact	Reason
1	V^^N_NIL_1	33:11:40	Voltage Stability	Vic - NSW Interconnector + Generators	Avoid voltage collapse around Murray for loss of all APD potlines
2	N_X_MBTE2_B	31:15:35	Unit Zero	Terranora Interconnector	Lower limit on Directlink, two cables out
3	N^N-LS_SVC	26:10:40	Voltage Stability	Terranora Interconnector	Avoid voltage collapse on trip of Armidale to Coffs Harbour (87), Lismore SVC out
4	N_X_MBTE_3B	21:08:45	Unit Zero	Terranora Interconnector	No flow on Directlink, all three cables out
5	N^^V_NIL_1	19:23:35	Voltage Stability	Vic - NSW Interconnector + Generators	Avoid voltage collapse at Southern NSW for loss of the largest Vic generating unit or Basslink
6	N^^N_NIL_2	18:12:30	Voltage Stability	NSW Generation + Interconnectors	Avoid voltage collapse at Darlington Point on trip of Darlington Point to Wagga 330 kV line (63)
7	N^^N_NIL_3	16:06:25	Voltage Stability	NSW Generation + Interconnectors	Avoid voltage collapse on trip of Bendigo-Kerang 220 kV line
8	Q^^NIL_QNI_SRAR	15:15:05	Voltage Stability	Qld Generation + Interconnectors	Avoid voltage collapse on trip of Sapphire- Armidale 330 kV line
9	N>>N-NIL_94T_947	15:05:45	Thermal	NSW Generation	Avoid overload of Molong to Orange North (94T) on trip of Wellington to Orange North (947)
10	N>N-NIL_CLDP_1	9:01:25	Thermal	NSW Generation	Avoid overload of Coleambally to Darlington Point (99T) on nil trip

Rank	Constraint ID	Total duration (dd:hh:mm)	Type	Impact	Reason
11	V^^N_HWSM_1	7:19:35	Voltage Stability	Vic - NSW Interconnector + Generators	Avoid voltage collapse around Murray for loss of all APD potlines, Hazelwood to South Morang out
12	N_X_MBTE_3A	7:18:15	Unit Zero	Terranora Interconnector	No flow on Directlink, all three cables out
13	N^^Q_NIL_B1	7:18:00	Voltage Stability	Qld Generation + Interconnectors	Avoid voltage collapse on loss of Kogan Creek generator
14	V>>V_NIL_9	6:21:35	Thermal	Victorian Generation + Interconnectors	Avoid overload of Waubra to Ballarat 220 kV line on trip of Kerang to Bendigo 220 kV line
15	Q::N_NIL_AR_2L-G	6:07:35	Transient Stability	NSW Generation + Interconnectors	Avoid transient instability for 2L-G fault at Armidale
16	N^^V_NIL_YW134_N-2	5:07:50	Voltage Stability	Vic - NSW Interconnector + Generators	Avoid voltage collapse at Southern NSW for loss of Yallourn units 1, 3 and 4 when declared credible and are the largest contingency
17	N>N-NIL_LSDU	4:23:35	Thermal	Terranora Interconnector	Avoid overload of Lismore to Dunoon (9U6 or 9U7) on trip of other Lismore to Dunoon line (9U6 or 9U7)
18	N_MBTE1_B	4:22:35	Unit Zero	Terranora Interconnector	Lower limit on Directlink, one cable out
19	V^^N_UTYS_1	4:13:50	Voltage Stability	Vic - NSW Interconnector + Generators	Avoid voltage collapse around Murray for loss of all APD potlines during Upper Tumut to Yass line 2 outage
20	V>>V_NIL_18	3:21:45	Thermal	Victorian Generation + Interconnectors	Avoid overload of Ararat to Waubra 220 kV line on trip of Kerang to Bendigo 220 kV line

The constraints listed in **Table A5.1** above are reviewed by TransGrid to fully understand their nature, and to provide possible solutions to reduce the market impact of the transmission constraints. The solutions for highly ranked constraints impacting the generators, NSW-QLD and VIC-NSW interconnectors are included in our proposed major developments and in subsystem developments described in **Sections 2.1.1** and **2.1.2** respectively[75].

75 NSW – QLD Terranora Interconnector dispatch is primarily impacted due to various outages of Directlink.

5.3 Transmission system performance – Market Impact

Table A5.2 summarises the top 20 constraints with the highest market impacts, measured by the marginal value. The table shows the constraint identifier, its description, type of limitation addressed by the constraint equation, the sum of the marginal values of the constraint binding and length of the time period where the transmission element, or the part of the transmission system, was operated at its maximum capability for the 12 month period (1 March 2020 to 28 February 2021).

Table A5.2: Marginal value of binding constraints

Rank	Constraint ID	Sum of Marginal Values	Total duration (dd:hh:mm)	Type	Impact	Reason
1	N^^N_NIL_2	$ 4,034,506.35	18:12:30	Voltage Stability	NSW Generation + Interconnectors	Avoid voltage collapse at Darlington Point on trip of Darlington Point to Wagga 330 kV line (63)
2	N>N-NIL_CLDP_1	$ 2,724,327.71	9:01:25	Thermal	NSW Generation	Avoid overload of Coleambally to Darlington Point (99T) on nil trip
3	N^^N_NIL_3	$ 1,633,965.92	16:06:25	Voltage Stability	NSW Generation + Interconnectors	Avoid voltage collapse on trip of Bendigo-Kerang 220 kV line
4	N>>N-NIL_94T_947	$ 1,393,811.80	15:05:45	Thermal	NSW Generation	Avoid overload of Molong to Orange North (94T) on trip of Wellington to Orange North (947)
5	N>>N-MPWW_ONE_8	$ 643,829.17	1:06:05	Thermal	NSW Generation	Avoid overload of Molong to Orange North (94T) on trip of Mt Piper to Wallerawang (71 or 70) during an outage of Mt. Piper to Wallerawang line (70 or 71)
6	N>N-NIL_9R4_99A	$ 613,791.65	2:05:50	Thermal	NSW Generation	Avoid overload of Finley to Mulwala 132 kV line (9R4) on trip of Finley to Uranquinty (99A) line
7	N::N_SDUT_2	$ 565,983.34	0:00:30	Transient Stability	Vic - NSW Interconnector + Generators	Avoid transient instability in the event of a fault during Upper Tumut – Stockdill line (01) outage
8	V>>V_NIL_9	$ 397,211.98	6:21:35	Thermal	Victorian Generation + Interconnectors	Avoid overload of Waubra to Ballarat 220 kV line on trip of Kerang to Bendigo 220 kV line
9	N::N_CRGR_2	$ 396,955.73	1:21:50	Transient Stability	Vic - NSW Interconnector + Generators	Avoid transient instability in the event of a fault during Crookwell to Gullen Range (3H) line outage
10	V^^N_NIL_1	$ 363,416.03	33:11:40	Voltage Stability	Vic - NSW Interconnector + Generators	Avoid voltage collapse around Murray for loss of all APD potlines
11	V>>V_NIL_14	$ 297,227.91	1:12:20	Thermal	Victorian Generation + Interconnectors	Avoid overload of Wemen to Kerang 220 kV line on trip of Horsham to Murra Warra to Kiamal 220 kV line
12	Q>>NIL_CLWU_RGLC	$ 264,123.69	0:21:25	Thermal	Qld Generation + Interconnectors	Avoid overload of Raglan to Larcom Creek (8875) on trip of Calvale to Wurdong (871) line
13	N_MBTE1_B	$ 263,970.61	4:22:35	Unit Zero	Terranora Interconnector	Lower limit on Directlink, one cable out
14	N>>N_DPYC_99D_C_1	$ 261,362.33	1:03:40	Thermal	NSW Generation + Interconnectors	Avoid overload of Darlington Point to Griffith (99K) line on trip of Darlington Point to Wagga (63) line during an outage of Darlington Point to Yanco (99D) line

Rank	Constraint ID	Sum of Marginal Values	Total duration (dd:hh:mm)	Type	Impact	Reason
15	I_QNI_ONE_PHASE_N-2	$ 248,927.93	0:18:05	Discretionary	NSW - Qld (QNI) Interconnector	QLD to NSW transfer limit when fault on both 8L and 8M circuits declared a credible contingency
16	V>>V_NIL_18	$ 165,825.01	3:21:45	Thermal	Victorian Generation + Interconnectors	Avoid overload of Ararat to Waubra line on trip of Kerang to Bendigo line
17	N>>N-PKWL_94K_2	$ 148,670.81	1:07:45	Thermal	NSW Generation	Avoid overload of Molong to Orange North (94T) line during Parkes to Wellington (94K) line outage
18	N^^Q_NIL_B1	$ 125,774.26	7:18:00	Voltage Stability	Qld Generation + Interconnectors	Avoid Voltage Collapse on loss of Kogan Creek
19	N::N_BYCR_UTYS_2	$ 123,043.79	0:15:30	Transient Stability	NSW Generation + Interconnectors	Avoid transient instability for a fault during Upper Tumut – Yass (2) line and Bannaby to Crookwell (61) line outage
20	N::N_CNSD_2	$ 120,219.94	0:00:20	Transient Stability	Vic - NSW Interconnector + Generators	Avoid transient instability for a fault during Canberra – Stockdill (3C) line outage

A5.4 Possible future transmission system performance

Table A5.3 summarises the maximum demand event for each of NSW, QLD and VIC that were analysed for the constraints that were binding (or violating) and the 10 constraints that were closest to binding at the time of the maximum demand in the period 1 March 2020 – 28 February 2021. The constraints that were not binding but close to binding were assessed to identify possible future transmission system limitations.

Table A5.3: Maximum demand event in NSW, QLD and VIC

Region	Max demand	Date and time
NSW	12,422 MW	Saturday 28 November 2020, 16:35
QLD	9,477 MW	Monday 22 February 2021, 17:45
VIC	8,285 MW	Monday 25 January 2021, 12:30

A5.4.1 Maximum demand event in New South Wales

Figure A5.1 shows a NEM overview map on the maximum demand event day in NSW. It summarises the power flow directions when the maximum demand occurred on Saturday 28 November 2020 at 16:35.

Figure A5.1: NEM overview map on Saturday 28 November 2020, 16:35

There were no binding or violating constraints in NSW on Saturday 28 November 2020, 16:35, i.e. when the demand in NSW reached maximum during the 1 March 2020 to 28 February 2021 period.

Table A5.4 summarises the NSW constraints that were close to binding on the maximum demand day of Saturday 28 November 2020 at 16:35.

Table A5.4: NSW constraints that were close to binding on Saturday 28 November 2020, 16:35

Rank	Constraint ID	Headroom (MW)	Type	Impact	Reason
1	N_MBTE1_B	53.9	Unit Zero	Terranora Interconnector	Lower limit on Directlink, one cable out
2	N>>N-NIL_94T_947	83.6	Thermal	NSW Generation	Avoid overload of Molong to Orange North (94T) on trip of Wellington to Orange North (947)
3	N>>N-NIL_94T	92.2	Thermal	NSW Generation	Avoid overload of Molong to Orange North (94T) on nil trip
4	N>N-NIL_MBDU	102.7	Thermal	Terranora Interconnector	Avoid overload of Mullumbimby to Dunoon (9U6 or 9U7) on trip of other Mullumbimby to Dunoon line (9U6 or 9U7)
5	N_NIL_TE_B	113.9	Unit Zero	Terranora Interconnector	Lower limit on Directlink
6	N>N-NIL_LSDU	162.7	Thermal	Terranora Interconnector	Avoid overload of Lismore to Dunoon (9U6 or 9U7) on trip of other Lismore to Dunoon line (9U6 or 9U7)
7	N>N-NIL_9R4_9R3	179.2	Thermal	NSW Generation	Avoid overload of Finley to Mulwala (9R4) on trip of Finley to Deniliquin (9R3)
8	N_MBTE1_A	183.1	Unit Zero	Terranora Interconnector	Upper limit on Directlink, one cable out
9	N>N-NIL_9R4_99A	188.9	Thermal	NSW Generation	Avoid overload of Finley to Mulwala (9R4) on trip of Finley to Uranquinty (99A)
10	N^^N_NIL_3	189.0	Voltage Stability	NSW Generation + Interconnectors	Avoid voltage collapse on trip of Bendigo-Kerang 220 kV line

A5.4.2 Maximum demand event in Queensland

Figure A5.2 shows a NEM overview map on the maximum demand event day in QLD. It summarises the power flow directions when the maximum demand occurred on Monday 22 February 2021 at 17:45.

Figure A5.2: NEM overview map on Monday 22 February 2021, 17:45

Table A5.5 summarises the NSW binding constraints on the maximum demand day in QLD (Monday 22 February 2021 at 17:45).

Table A5.5: NSW binding constraints on Monday 22 February 2021, 17:45

Constraint ID	Type	Impact	Reason
N^^N_NIL_3	Voltage Stability	NSW Generation + Interconnectors	Avoid voltage collapse on trip of Bendigo-Kerang 220 kV line
N^^Q_NIL_B1	Voltage Stability	Qld Generation + Interconnectors	Avoid voltage collapse on loss of Kogan Creek

Table A5.6 summarises the NSW constraints that were close to binding on the maximum demand day in QLD (Monday 22 February 2021 at 17:45).

Table A5.6: NSW constraints that were close to binding on Monday 22 February 2021, 17:45

Rank	Constraint ID	Headroom (MW)	Type	Impact	Reason
1	N>N-NIL_LSDU	10.3	Thermal	Terranora Interconnector	Avoid overload of Lismore to Dunoon (9U6 or 9U7) on trip of other Lismore to Dunoon line (9U6 or 9U7)
2	N^^N_NIL_2	49.4	Voltage Stability	NSW Generation + Interconnectors	Avoid voltage collapse at Darlington Point on trip of Darlington Point to Wagga 330 kV line (63)
3	N>>N-NIL_94T_947	66.3	Thermal	NSW Generation	Avoid overload of Molong to Orange North (94T) on trip of Wellington to Orange North (947)
4	N>>N-NIL_94T	67.8	Thermal	NSW Generation	Avoid overload of Molong to Orange North (94T) on nil trip
5	N>>N-PKWL_94K_2	68.7	Thermal	NSW Generation	Avoid overload of Molong to Orange North (94T) on nil trip, Parkes to Wellington (94K) out
6	N>>N-PKWL_94K_3	80.0	Thermal	NSW Generation	Avoid overload of Molong to Orange North (94T) on trip of Wellington to Orange North (947), Parkes to Wellington (94K) out
7	N>N-NIL_997_99A	81.6	Thermal	NSW Generation	Avoid overload Corowa to Albury (997/1) on trip of Finley to Uranquinty (99A)
8	N>N-NIL_9R4_99A	84.7	Thermal	NSW Generation	Avoid overload of Finley to Mulwala (9R4) on trip of Finley to Uranquinty (99A)
9	N>N-NIL_TE_D2	106.3	Thermal	Terranora Interconnector	Avoid overload of Lismore 330 to Lismore 132 (9U9) on trip of Lismore 330 to Lismore 132 (9U8)
10	N_NIL_TE_A	110.0	Unit Zero	Terranora Interconnector	Upper limit on Directlink

A5.4.3 Maximum demand event in Victoria

Figure A5.3 shows a NEM overview map on the maximum demand event day in VIC. It summarises the power flow directions when the maximum demand occurred on Monday 25 January 2021 at 12:30.

Figure A5.3: NEM overview map on Monday 25 January 2021, 12:30

Table A5.7 summarises the NSW binding constraints on the maximum demand day in VIC (Monday 25 January 2020, 12:30).

Table A5.7: NSW binding constraints on Monday 25 January 2021, 12:30

Constraint ID	Type	Impact	Reason
N>>N-NIL_94T_947	Thermal	NSW Generation	Avoid overload of Molong to Orange North (94T) on trip of Wellington to Orange North (947)
N>>V-NIL_OX1	Thermal	NSW Generation + Interconnectors	Avoid overload of Buronga to Redcliff (OX1) on nil trip

Table A5.8 summarises the NSW constraints that were close to binding on the maximum demand day in VIC (Monday 25 January 2021, 12:30).

Table A5.8: NSW constraints that were close to binding on Monday 25 January 2021, 12:30

Rank	Constraint ID	Headroom (MW)	Type	Impact	Reason
1	N>N-NIL_9R4_9R3	30.9	Thermal	NSW Generation	Avoid overload of Finley to Mulwala (9R4) on trip of Finley to Deniliquin (9R3)
2	N>N-NIL_9R4_99A	31.2	Thermal	NSW Generation	Avoid overload of Finley to Mulwala (9R4) on trip of Finley to Uranquinty (99A)
3	N>>N-NIL_94T	36.5	Thermal	NSW Generation	Avoid overload of Molong to Orange North (94T) on nil trip
4	N>N-NIL_9R4	73.5	Thermal	NSW Generation	Avoid overload of Finley to Mulwala (9R4) on nil trip
5	N>N-NIL_MBDU	79.8	Thermal	Terranora Interconnector	Avoid overload of Mullumbimby to Dunoon (9U6 or 9U7) on trip of other Mullumbimby to Dunoon line (9U6 or 9U7)
6	N>N-NIL_CLDP_1	96.2	Thermal	NSW Generation	Avoid overload of Coleambally to Darlington Point (99T) on nil trip
7	N_NIL_TE_B	105.0	Unit Zero	Terranora Interconnector	Lower limit on Directlink
8	N>>N-NIL_94B	162.3	Thermal	NSW Generation	Avoid overload of Beryl to Wellington (94B) on nil trip
9	N>N-NIL_LSDU	190.2	Thermal	Terranora Interconnector	Avoid overload of Lismore to Dunoon (9U6 or 9U7) on trip of other Lismore to Dunoon line (9U6 or 9U7)
10	N>>N-NIL_DPTX	219.4	Thermal	NSW Generation + Interconnectors	Avoid overload of Darlington Point Tx3 or Tx4 on trip of the other

Appendix 6

Glossary

Term	Explanation/Comments
AEMC	The Australian Energy Market Commission
AEMO	The Australian Energy Market Operator. Responsible for operation of the NEM and has the role of Victorian Jurisdictional Planning Body (JPB)
AER ('the regulator')	The Australian Energy Regulator
Assets	TransGrid's 'towers and wires', all the substations and electricity transmission lines that make up the network
Augmentation	Expansion of the existing transmission system or an increase in its capacity to transmit electricity
Bulk supply point (BSP)	A point of supply of electricity from a transmission system to a distribution system
Connection point	The agreed point of supply established between the network service provider and another registered participant or customer
Constraint (limitation)	An inability of a transmission system or distribution system to supply a required amount of electricity to a required standard
Consumers	Any end user of electricity including large users, such as paper mills, and small users, such as households
Demand	The total amount of electrical power that is drawn from the network by consumers. This is talked about in terms of 'maximum demand' (the maximum amount of power drawn throughout a given period) and 'total energy consumed' (the total amount of energy drawn across a period)
Demand management (DM)	A set of initiatives that are put in place at the point of end-use to reduce the total and/or maximum consumption of electricity
Direct customers	TransGrid's customers are those directly connected to our network. They are either Distribution Network Service Providers, directly connected generators, large industrial customers, customers connected through inter-regional connections or potential new customers
Distribution Network Service Provider, DNSP (Distributor)	An organisation that owns, controls or operates a distribution system in the National Electricity Market. Distribution systems operate at a lower voltage than transmission systems and deliver power from the transmission network to households and businesses
Easement	A designated area in which TransGrid has the right to construct, access and maintain our assets, while ownership of the property remains with the original land owner
Electricity Statement of Opportunities (ESOO)	A document produced by AEMO that focuses on electricity supply demand balance in the NEM
Embedded generation	A generating unit connected to the distribution network, or connected to a distribution network customer. (Not a transmission connected generator)
Generator	An organisation that produces electricity. Power can be generated from various sources, e.g. coal fired power plants, gas-fired power plants, solar and wind farms
Interconnection	The points on an electricity transmission network that cross jurisdictional/state boundaries
ISP	Integrated System Plan
Jurisdictional Planning Body (JPB)	The organisation nominated by a relevant minister as having transmission system planning responsibility in a jurisdiction of the NEM
Load	The amount of electrical power that is drawn from the network
Local generation	A generation or cogeneration facility that is located on the load side of a transmission constraint
LRET	Large Scale Renewable Energy Target
'N – 1' reliability	The system is planned for no loss of load on the outage of a single element such as a line, cable or transformer
National Electricity Law	Common laws across the states which comprise the NEM, which make the NER enforceable
National Electricity Market (NEM)	The National Electricity Market, covering Queensland, New South Wales, Victoria, South Australia and Tasmania
National Electricity Rules (NER or 'the Rules')	The rules that govern the NEM. The Rules are administered by the AEMC
Native energy (demand)	Energy (demand) that is inclusive of Scheduled, Semi-Scheduled and Non-Scheduled generation

Term	Explanation/Comments
NEFR	National Electricity Forecasting Report
Non-network options	Alternatives to network augmentation which address a potential shortage in electricity supply in a region, e.g. demand response or local generation
NSCAS	Network Support and Ancillary Services. Services used by AEMO that are essential for managing power system security, facilitating orderly trading, and ensuring electricity supplies are of an acceptable quality.
NSW region	With respect to energy consumption and demand, the term 'NSW region' refers to the combined NSW and ACT electricity loads
NTFP	National Transmission Flow Path
NTNDP	National Transmission Network Development Plan
Outage	An outage is when part of the network is switched off. This can be either planned (i.e. when work needs to be done on the line) or unplanned
POE	Probability of Exceedence. This is the probability a forecast would be met or exceeded, e.g. a 50% POE demand implies there is a 50% probability of the forecast being met or exceeded
PV	Photovoltaic
RAS	Remedial Action Scheme used to take action on the HV Network during special operating conditions.
Reliability	Reliability is a measure of a power system's capacity to continue to supply sufficient power to satisfy customer demand, allowing for the loss of generation capacity
RET	Renewable Energy Target
RIT-T	Regulatory Investment Test for Transmission
Secondary system	Equipment used to control, automate, protect and monitor the network
Substation	A set of electrical equipment used to step high voltage electricity down to a lower voltage. Lower voltages are used to deliver power safely to small businesses and residential consumers
SVC	Static VAr Compensator. An electrical device installed on the high voltage transmission system to provide fast acting voltage control to regulate and stabilise the system
Transmission Annual Planning Report (TAPR)	This document that sets out issues and provides information to the market that is relevant to transmission planning in NSW
Transmission line	A high voltage power line running at 500 kV, 330 kV, 220 kV or 132 kV. The high voltage allows delivery of bulk power over long distances with minimal power loss
Transmission Network Service Provider (TNSP)	A body that owns, controls and operates a transmission system in the NEM

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