Distribution and Transmission Annual Planning Report

December 2023

Ausgrid

Foreword

The impacts of electrification, decarbonisation, and decentralisation continue to accelerate as governments and society seeks to limit the impacts of climate change and achieve net zero emissions by 2030. Like many electricity network operators around the globe, Ausgrid is faced with the challenge of cost effectively enabling this transformation, and promoting the long-term interests of the customers and communities we serve.

The last 12 months has seen a substantial increase in the rate of customer energy resource (CER) adoption in our network area, including rooftop solar systems, battery installations and electric vehicles. Over the same period we have also seen a sharp increase in level of connection activity associated with grid scale generation and storage projects.

In responding to these changes, Ausgrid is actively pioneering new approaches and technologies to enable customers to get maximum value from their energy investments, and help NSW meet its net zero goals.

Ausgrid is further supporting energy transition through the development of new infrastructure such as Battery Energy Storage Systems (BESS), Electric Vehicle Charging Infrastructure (EVCI) and Renewable Energy Zones (REZ), in line with the NSW Government's [Electricity Infrastructure Roadmap](#).

Over the past year, Ausgrid has:

- Commissioned three Stand-alone Power Systems (SAPS) in the Upper Hunter network area (Singleton), to improve reliability, resilience and reduce costs for customers. Over the coming year, Ausgrid is continuing Phase 2 of the SAPS trial across the Hunter region with interested landowners;
- Delivered the first two community batter under the Government's Community Batteries for Household Solar Program, at Cabarita in Sydney's Inner West and Narara in the Central Coast. These are the first of six community batteries Ausgrid is delivering under this program. The next will be installed in the following suburbs - Bondi/Bondi Beach, Cammeray, Warriewood and North Epping. Community batteries can help increase the renewable energy available to local communities and prepare the grid for increased electricity demand from electric vehicle charging;
- Connected 25 JOLT EV charging sites at our distribution substations, increasing the number of available EV smart chargers, promoting EV adoption;
- Partnered with Upper Hunter Shire Council and Merriwa community to trial a microgrid technology, and deliver a more responsive, resilient and reliable power supply to the community. Ausgrid is currently finalising the microgrid design phase to begin construction in the coming year;
- Awarded Energy Network Australia's 2023 Industry Innovation Award for Project Edith, a project known as a world-leading innovation that showcases how the grid can facilitate the participation of green energy solutions in the energy market while staying within distribution network capacity limits;
- Contributed to collaborative research through our involvement with Reliable Affordable Clean Energy (RACE) for 2030 and the International Community for Local Smart Grids focused on local solutions for the net-zero transition.

This year, the Distribution and Transmission Annual Planning Report (DTAPR) has been divided into two separate documents. This one serves as a summary, focusing on the Ausgrid's strategies, accomplishments, and challenges as a distribution network service provider. The main DTAPR outlines our 2023 annual planning review and delineates our obligations as a Distribution and Transmission Network Service Provider in the National Electricity Market.

Looking forward to the 2024-2029 period, we anticipate challenges and opportunities in the following areas:

- Building resilience to climate change
- Transitioning to net zero
- Providing efficient infrastructure
- Providing an affordable service
- Continuing the path to digitisation

This report provides an overview of our plans and strategies for the forward planning period. If you have enquiries, please reach out to us at assetinvestment@ausgrid.com.au.

Junayd Hollis

Group Executive - Customer, Assets and Digital

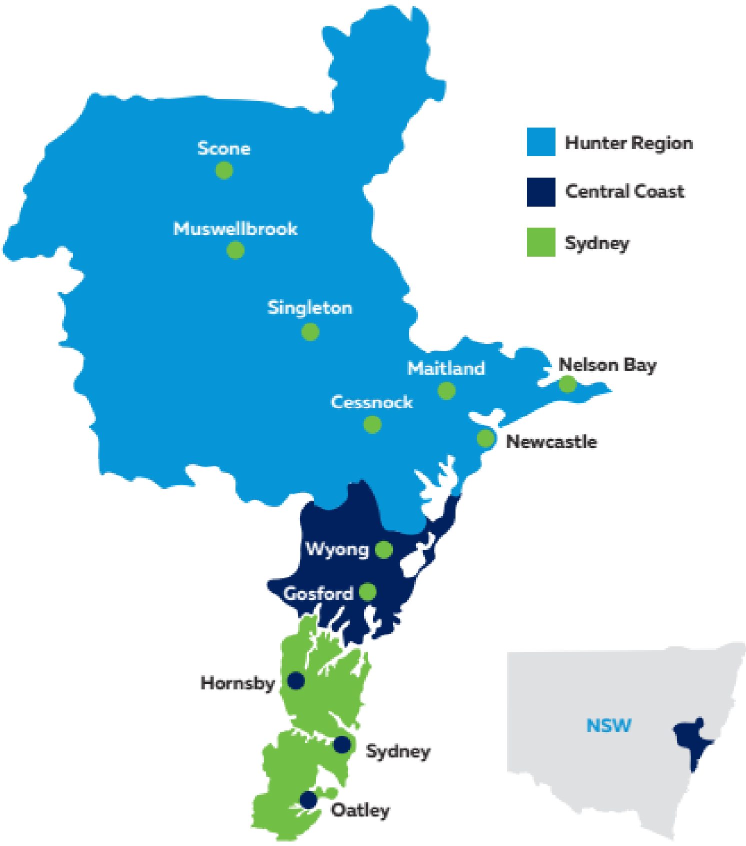
About Ausgrid

Ausgrid is operated under a long-term lease via a partnership between the NSW Government and AustralianSuper, APG Asset Management Group and IFM Investors where 49.6% of interest and share are held by the NSW Government.

Ausgrid owns and operates the network of substations, powerlines, underground cables and power poles, that deliver power to communities across large parts of Greater Sydney, the Central Coast and the Hunter. Ausgrid's network is a shared asset that connects communities and empowers the lives of our customers and their communities today and for over a century.

Our core business is to provide distribution network services to our customers. Each day we build, operate and maintain the network with a focus on providing a safe, reliable, affordable and sustainable energy supply. The wide range of services we provide is illustrated on the next page.

We're investing now for a future where renewables play a dominant role and where households and businesses can generate their own energy and sell it back to the grid. The grid has a pivotal role in supporting customers during this energy transformation. We are committed to working with our customers and stakeholders to realise an efficient lower carbon future.



Our Network

- Supports over 20% of the national gross domestic product
- Serves over 4 million people in almost 1.8 million homes and businesses
- Covers 22,275 km2 made up of large and small substations connected through high and low voltage powerlines, underground cables and power poles
- Includes most densely populated areas in NSW
- Supplies customers as far north as the Upper Hunter Valley, as far south as Waterfall and to Auburn in Sydney's west

Ausgrid Network Includes

Dual function transmission system

132kV transmission assets operated in parallel to and in support of the main transmission system

Sub-transmission system

33kV, 66kV and 132kV assets

High Voltage distribution system

Predominantly 11kV, with some 5kV, 22kV and 33kV and 12.7kV Single Earth Wire Return assets

Low Voltage distribution system

400V assets (230V single phase)

Operating Environment

Ausgrid is regulated by statutory and legislative requirements, including Work Health and Safety (WH&S), environmental, competition, industrial, consumer protection and information laws, National Electricity Regulation (detailed below), and the NSW Electricity Supply Act 1995 (ESA). We must also comply with the conditions of our NSW Distribution Network Service Provider licence (under the ESA) and Security of Critical Infrastructure Act 2018.

The National Electricity Regulation is primarily represented by the National Electricity Law (NEL) and National Electricity Rules (NERs) which regulate the National Electricity Market, and the National Energy Customer Framework. Ausgrid operates in the National Electricity Market (NEM) as both a distribution and transmission network service provider (DNSP and TNSP). The National Electricity Objective (NEO), as stated in the National Electricity Law is 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:

(a) price, quality, safety, reliability and security of supply of electricity; and

(b) the reliability, safety and security of the national electricity system."

We meet these obligations with investments that address our customers' requirements for safe, affordable, reliable and sustainable network services.

We manage compliance with these laws and regulations through our internal codes and policies and a common control framework. This control framework comprises plans, policies, procedures, delegations, instruction and training, audit and risk management.

Our Purpose

Our purpose is *'connecting communities, empowering lives'.*

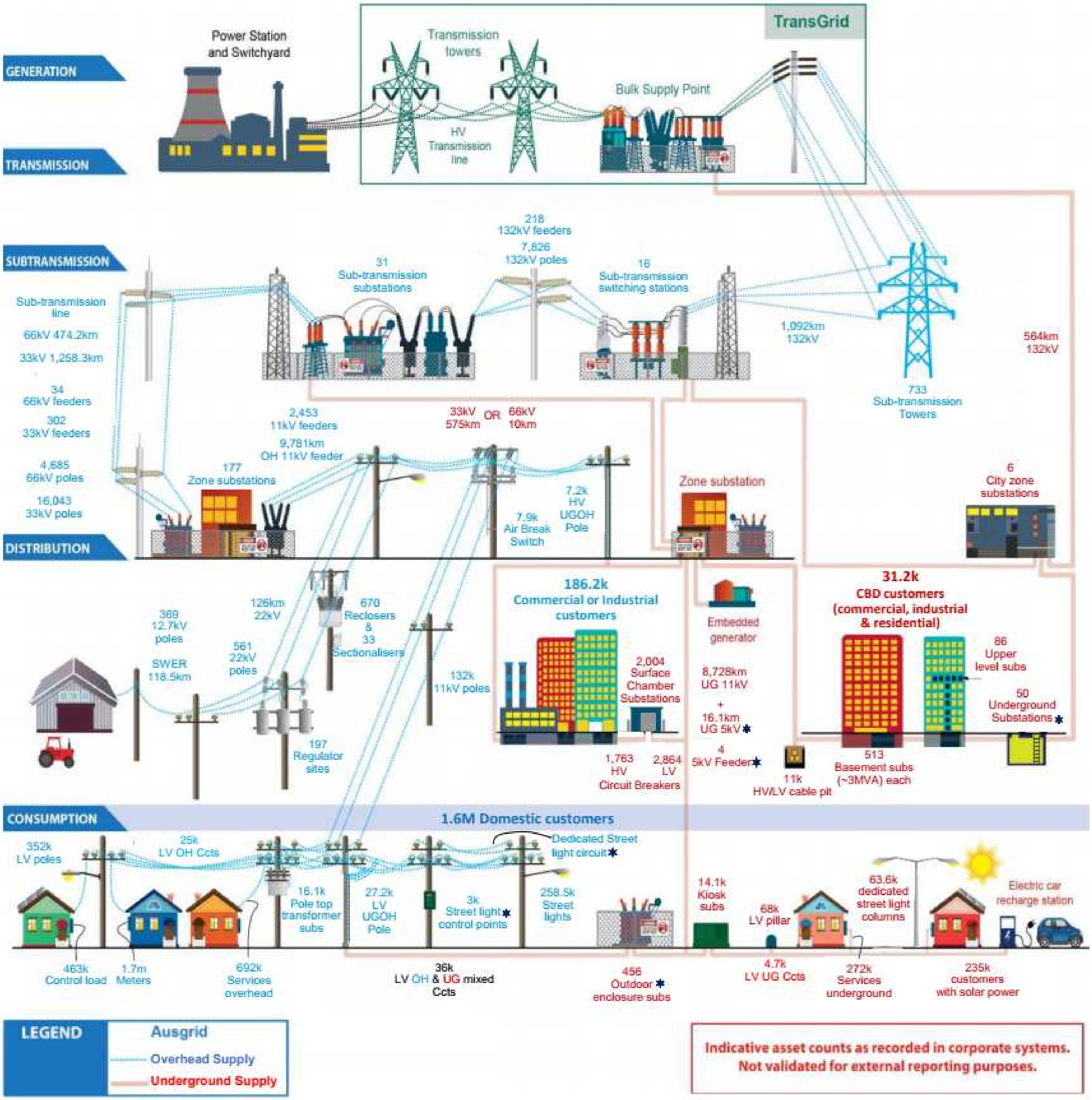
Our Vision

Our vision is for communities to have the power in a resilient, affordable, net-zero future.

Our Values

- Work safe, live safe
- Customer-focused
- Commercially minded
- Collaborative
- Honest and accountable
- Respect

State of the Network



Other Network Asset Statistics	2022/23
Dual function (Transmission) System – 132kV (km)	889
Low Voltage Overhead (km)	13,133
Low Voltage Underground (km)	7,052
Streetlighting Overhead (km)	3,420
Streetlighting Underground (km)	1,173

NOTES:

- Asset counts and lengths do not include private assets.

Purpose of the Distribution and Transmission Annual Planning Report

This DTAPR complies with National Electricity Rules (NER) clause 5.13.2 "Distribution Annual Planning Report" (DAPR) and clause 5.12.2 "Transmission Annual Planning Report" (TAPR), utilising Version 200 of the NER. Ausgrid has prepared this DTAPR with a five-year forward planning horizon, reflecting the outcomes of the annual planning review of Ausgrid's electricity network since the December 2022 DTAPR publication.

The purpose of this document is to inform Registered Participants, stakeholder groups and interested parties of the identified future network needs, the committed and proposed solutions to these needs and the potential opportunities for non-network solutions, particularly for large investments where the Regulatory Investment Test for Distribution (RIT-D) applies.

Ausgrid's DTAPR aligns with the NER Schedule S5.8 Distribution Annual Reporting Requirements to:

- Provide transparency to Ausgrid's decision making processes and assist non-network providers, other Network Service providers and connection applicants to make efficient investment decisions;
- Promote efficient investment decisions in the electricity market;
- Include information on the planning process encompassing forecasting, identification of network limitations, and the development of potential credible options to address these limitations;
- Present the results of Ausgrid's annual planning review, including joint planning with other Network Service Providers, covering a minimum five year forward planning period for distribution assets;
- Offer third parties the opportunity to offer alternative proposals to the identified network needs, including non-network solutions such as demand management or embedded generation;
- Provide network capacity, load forecasts and hosting capacity for embedded generation for subtransmission lines, zone substations and transmission-distribution connection points, and any 11kV primary distribution feeders which are constrained or are forecast to be constrained within the next two years; and
- Provide information on Ausgrid's demand management activities and actions taken to promote non-network initiatives each year, including plans for demand management and embedded generation over the forward planning period.

Distribution and Transmission Annual Planning Review and Reporting

Ausgrid owns, develops, operates and maintains transmission dual function assets in NSW that are operated in parallel with Transgrid's network, and perform a transmission function by supporting the main NSW transmission network. Ausgrid is therefore also registered as a TNSP and is required to publish a TAPR covering our dual function assets. The NER permit Ausgrid to publish its TAPR as part of the DAPR to align the publication of both reports each year.

Reporting of both planning reviews have been merged into one document. The information that the NER requires Ausgrid to report for both distribution and transmission is covered throughout the various sections of the DTAPR.

Significant Changes from Previous DTAPR

For the past two years, Ausgrid introduced several developments including a new online portal displaying Ausgrid's network interactively. The structure of the 2022 DTAPR and associated data files has slightly changed. This year, we have introduced a DTAPR summary which focuses on Ausgrid's strategies, accomplishments throughout the year, and challenges we face as a distribution network service provider. This summary has been graphically enhanced for readability purposes. The summary document contains the first chapter "Upcoming Challenges" amongst the Foreword and About Ausgrid. The structure of the main DTAPR document remains unchanged from last year.

This year information regarding the system strength has been included in the mapping portal to comply with 5.12.2 (c)(13) and S5.8(q).

In addition, the associated data files mainly remain unchanged, with some structure/graphical enhancements to the Substation Capacity and Demand Forecast, Dual Function Asset 10-year Demand Forecast, Generator Export and Hosting Capacity, and System Limitation template, to assist with readability.

System Limitations Template – Online Data

Since 2017 Ausgrid has published online data in the format prescribed by the Australian Energy Regulator (AER) in a Distribution System Limitation Template.

Following the release of the TAPR guidelines in December 2018, we have populated a Transmission System Limitation Template, and this is included again this year.

Online data associated with the 2023 DTAPR, as well as the document itself, is accessible via Ausgrid's website at www.ausgrid.com.au/DTAPR.

Disclaimer

Ausgrid is registered as both a Distribution Network Service Provider and a Transmission Network Service Provider. This DTAPR 2023 has been prepared and published by Ausgrid under clause 5.13.2 and 5.12.2 of the National Electricity Rules to notify Registered Participants and Interested Parties of the results of the distribution and transmission network annual planning review and should only be used for those purposes.

This document does not purport to contain all of the information that a prospective investor or participant or potential participant in the National Electricity Market, or any other person or interested parties may require. In preparing this document it is not possible nor is it intended for Ausgrid to have regard to the investment objectives, financial situation and particular needs of each person who reads or uses this document. In all cases, anyone proposing to rely on or use the information in this document should independently verify and check the accuracy, completeness, reliability and suitability of that information for their own purposes.

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Guide To This Document

We are the custodians of a network that connects communities and empowers the lives of our 1.8 million customers, and have done so for over a century. Ausgrid operates as both a transmission and a distribution network service provider. Our network is made up of approximately 30,000 substations connected through high and low voltage power lines, underground cables, tunnels and power poles. Our operations include infrastructure construction, maintenance and operation, customer connections, street lighting and telecommunications. We are increasingly involved in supporting the transition to a net zero economy through the connection of renewable energy to the grid, by the electrification of loads such as transport via electric vehicles and by supporting the NSW Government's Electricity Infrastructure Roadmap through the development of renewable energy zones.

The DAPR section of this document covers a five year forward planning period, while the TAPR section covers a ten year forward planning period, from December 2023. Our 2023 DTAPR document is accessible via Ausgrid's website www.ausgrid.com.au/DTAPR, with the supporting data at our new online portal located at https://dtapr.ausgrid.com.au.

This data has been structured to enable you to easily target the key locations and come to us with solutions that more readily meet the needs of our customers and grid.

Chapter 1: Upcoming Challenges

Ausgrid must achieve high levels of availability and reliability in its network. At the same time, we must act to respond to:

- climate change risks and community resilience needs.
- the implementation of infrastructure and maintaining an affordable service in the transition to net zero.
- external threats to our network like cyber threats.
- increasing needs to transform our digital platforms.

Chapter 2: Network Investments

In consideration of network limitations identified during the planning process, credible network options have been identified to:

- address the deteriorating condition of network assets.
- connect customers, including customer driven network augmentations.
- implement reliability correction actions.
- deliver improvements in automation/control systems.

Network investments that will be the subject of a RIT-D in the forward planning period will be reported here.

Chapter 3: Non-Network Opportunities

Ausgrid welcomes and encourages feedback from market participants and alternative proposals to address identified network limitations by means of demand management options.
This section also provides information about demand management and embedded generation activities in progress and for the forward planning period.

Chapter 4: Asset Management

Ausgrid's approach to manage its network assets is described here, including a description of the risk management strategies applied to the asset categories that require the most significant investments in the forward planning period. This section also discusses distribution network losses.

Chapter 5: Network Performance

A review of the network from a reliability and quality of supply perspective is reported here. The results are compared against specific targets set in the Licence Conditions given to Ausgrid. This comparison also includes the Service Target Performance Incentive Scheme (STPIS), which is set by the Australian Energy Regulator (AER) as part of its regulatory determination for Ausgrid.
A forecast of the network reliability performance is also provided in this chapter.

Chapter 6: Network Demand and Limitations

This section details the location of identified system limitations and the dual function assets in the network. It also displays the system total maximum demand forecast, discusses frequency control load, load shedding, stability and primary distribution feeder limitations.

Chapter 7: Planning Coordination

Joint Planning is carried out with EnergyCo and peer Network Service providers such as Transgrid, Endeavour Energy and Essential Energy. Activities conducted with all these entities are reported, providing an overview of the decisions/actions in each case.

Chapter 8: IT & Communications

A description of the key Information Technology and Communication Systems supporting Ausgrid's business is provided in this chapter, including details of the strategies and investments in progress as well as those proposed for the forward planning period.

Appendix

Ausgrid's approach to network planning and forecasting methodology are described here. This section describes the approach taken, the assumptions considered in the forecast, and the factors having a material impact on the network. Consideration is also given to emerging trends, such as growth in solar installations, future battery installations and electric vehicle uptake. A Glossary is also included.

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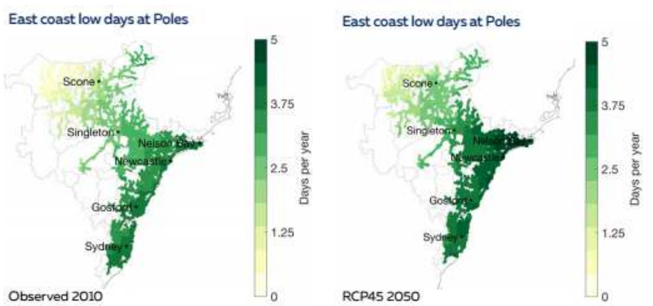
1. Upcoming Challenges

1.1 Building resilience to climate change

Building resilience to climate change involves developing strategies, actions, and policies to enhance the ability of communities to withstand, adapt to, and recover from the challenges and disruptions posed by climate change.

Weather and climate extremes pose a significant danger to Australia's electricity network. Human-induced climate change is amplifying the frequency and intensity of certain extreme events, further aggravating these risks.

- Australia will experience higher temperatures, and intensified storms, floods and bushfires due to climate change.
- Actions to mitigate temperature rises through electrification make building resilience of our network even more important.
- Our customers have made it clear that resilience is a priority that they want us to invest in.



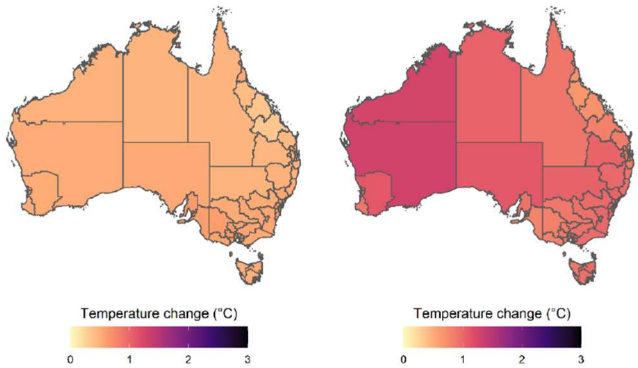
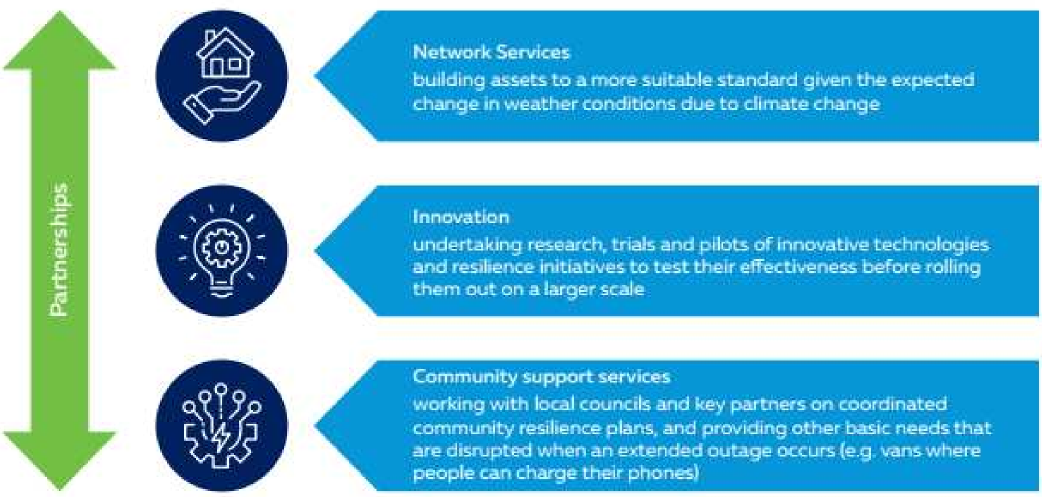


Figure 1-1 Changes in temperatures under 2 and 3 degrees Celsius in the long term. Based on Bureau of Meteorology data provided for the Intergenerational Report 2023 – Australia's future to 2063

To better understand the growth in Ausgrid's climate risk profile to 2050, we commissioned climate scientists to establish an understanding of the climate risks in our operating region. The climate risk assessment showed that the areas with the biggest exposure from climate change is from windstorms in the coastal regions. Under the mid-range climate scenario (RCP4.5) the increasing speed of maximum wind gusts and rising frequency of major storm events to 2050 due to climate change, when combined with Ausgrid network and load data, has been shown to result in a ~1% per annum increase in asset repair and unserved energy costs across Ausgrid's 11kV distribution network. Ausgrid has proposed adaptation investments as part of our Regulatory Proposal to mitigate this increase in risk.

Spectrum of Resilience

Building climate resilience involves reducing the risks associated with increasing severe weather events, including more network outages, as well as bolstering our capacity to aid communities during such outages whilst promptly restoring power. In crafting resilience strategies, Ausgrid intends to implement targeted solutions that address distinct resilience requirements.

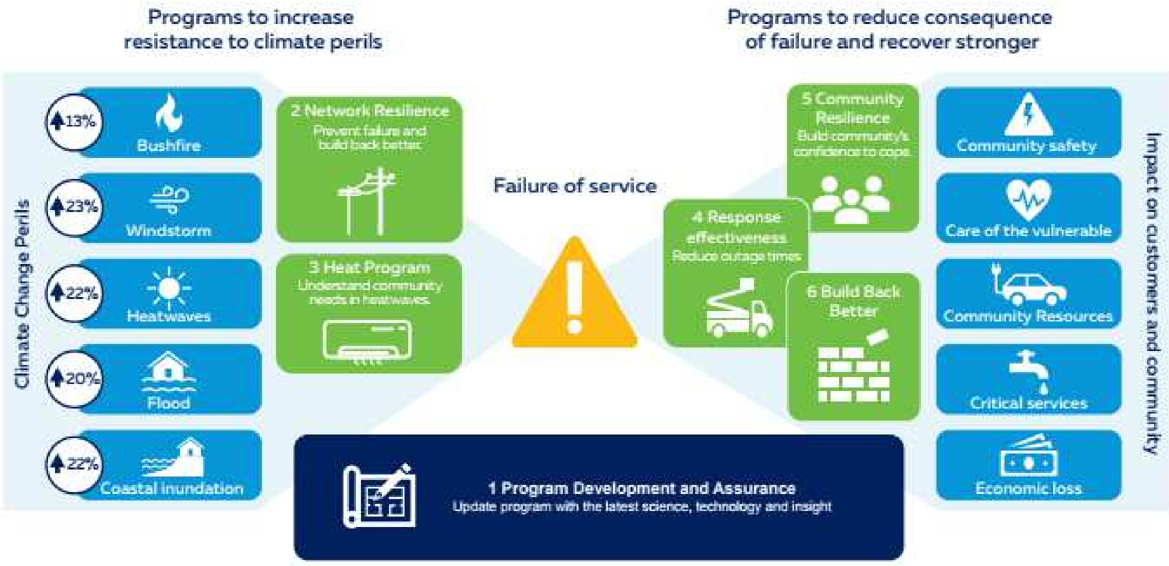


Climate resilience initiatives

Ausgrid already has programs for resilience and works with emergency service partners to prepare for these events. The Climate resilience program is about preparing for the future on top of what we already do. Ausgrid has codesigned this proposal with customers, including deep engagement with communities to understand the solutions they prefer.

Ausgrid has a holistic approach to preparing for the climate change risks including programs to:

- improve our understanding of climate change risk;
- improve resistance to climate perils;
- reduce the consequence of failure, and to recover stronger.



Approaches to building resistance to climate perils include:

- Installing stronger powerlines in areas with large amounts of vegetation, by replacing bare conductors with covered conductor technology and introducing segmentation in the network via interrupters/reclosers.
- Considering of undergrounding segments of the network.

Approaches to reducing consequence of failure include:

- Improving the way we share data with Emergency Services for better multi agency response
- Understanding the needs of our customers

Approaches to build back stronger include:

- Investments in bushfire resistant poles

We are proud to be working in collaboration with partners and the community to prepare for the future.

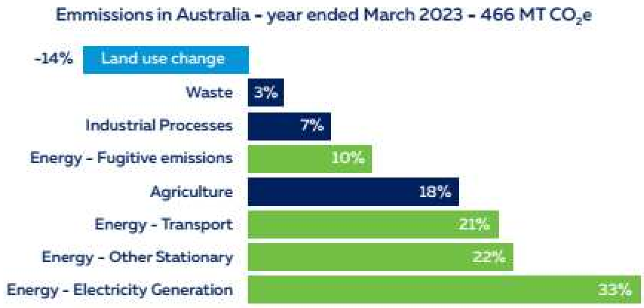
SAPS & Microgrids

- Ausgrid is investing in SAPS and microgrids to reduce outage times for customers and communities as well as reducing risk of fires in bushfire prone areas.
- SAPS are off grid electricity systems, generally comprised of solar photovoltaic arrays, energy storage and backup diesel generators.
- A microgrid may be completely disconnected from the electricity network or it can be connected to the main electricity network with the ability to deenergise the main line for network maintenance or an impending extreme weather event.
- SAPS and microgrids reduce bushfire risk as electricity infrastructure, that could potentially spark igniting a bushfire, is either no longer energised or removed.
- It is expected that the cost to supply customers will fall if DNSPs provide SAPS on a permanent basis, leading to a reduction in network charges for the entire customer base.
- They can also be used by electricity networks as practical solutions to make communities more resilient to extreme weather events and natural disasters as they enable a customer or community to isolate and remain energised in an emergency. This is particularly important for keeping telecommunication towers and fire-fighting equipment (water pumps) operational.
- As distribution network's experience more natural disasters such as bushfires, storm events and floods, SAPS can also be utilised in an emergency to replace assets, allowing utilities to effectively provide the updated power solutions for our customers rather than replacing assets like for like.

1.2 Transitioning to net zero

The energy sector is the main source of greenhouse gas emissions, making it imperative to transition to renewable energy sources to mitigate the impacts of climate change. Net zero is a state where the overall emissions balance is zero by 2050. Many sectors of the economy will have achieved zero emissions by that time.

Ausgrid is taking measures to support this transition. A net-zero future presents opportunities for Ausgrid, as greater electrification will be achieved by switching transport and household fuel consumption powered from fossil fuels to electricity from renewable sources. Significant efforts will also be made to support the connection of new renewable generation into the network.



Source: Australia's National Greenhouse Accounts
Australian Government, Department of Climate Change, Energy, the Environment and Water

Greater Participation of CER in the energy market

Ausgrid expects that by 2030:

- Solar customers will increase from approximately 250,000 to more than 400,000.
- Household batteries will increase from approximately 17,000 to more than 130,000.
- Electric Vehicles (EVs) using our network will increase from 3,000 to more than 500,000.

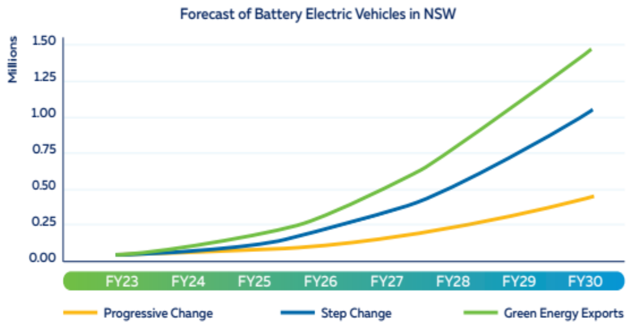
The number of Customer Energy Resources (CER) in our network will double, from 0.75 million in 2023 to 1.50 million in 2030.

The consequence of this is the decentralisation of supply. The original one-way energy flow design of our network must evolve to manage bi-directional energy flows. Whilst CER can provide significant benefits to customers in terms of participation in energy markets, it also brings technical challenges for Ausgrid's network in terms of hosting capacity, network overloads and curtailment.

Actions to support an efficient transition to net zero and greater CER integration are outlined below.

Encouraging Adoption of Electric Vehicles

- All scenarios assume cost parity (i.e., the full cost of owning and operating a vehicle, without subsidies) between EVs and Internal Combustion Engine Vehicles should happen before 2030.
- EVs circulating in NSW are expected to increase from approximately 30,000 vehicles in 2023 to over 1 million vehicles by 2030 (based on AEMO's Step Change scenario). At least half of these vehicles will be using Ausgrid's network.



Source: Australian Energy Market Operator (AEMO)
2023 Inputs, Assumptions and Scenarios Report - July 2023

Ausgrid has the objectives of:

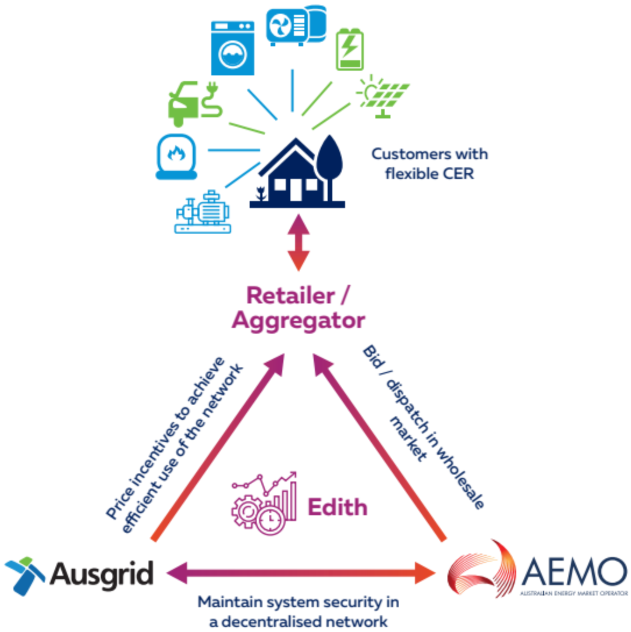
- Building and operating a fleet of 10,000 curb side EV chargers by 2030, in partnership with local city councils and .
- Continuing the roll out of JOLT EV charging stations providing up to 7KWh of free, fast charging for drivers.

To help those households that cannot afford their own home batteries, Ausgrid has the objectives of:

- Installing community batteries up to 250KW / 500KWh in the low voltage network, and

Accelerate electrification

- Installing 5MW /10MWh Battery Energy Storage Systems in the 11kV network near substations, to provide storage services to local residential and small business customers.

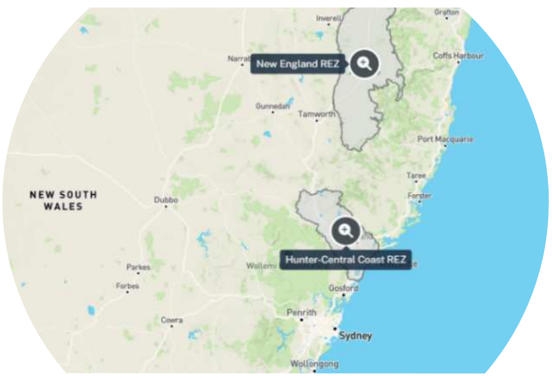


To help communities achieving greater electrification from sustainable sources, Ausgrid is expected to:

- Co-install solar arrays in places of interest for local communities, in coordination with councils.
- Increase LED rollout for public lighting.

To further reduce our carbon footprint, Ausgrid will continue to:

- Upgrade the fleet of passenger vehicles with EVs or hybrid vehicles to reduce fleet emissions by 40%.
- Expand EV trials to excavators, utility vehicles and trucks.



In addition to finding ways to store energy, customers will be encouraged to participate in energy markets. Traditional network tariffs and static export limits can create barriers. To support the shift to a two-sided market, Ausgrid has the objective of:

- Improving network access and trade opportunities by using dynamic operating envelopes (changes in network limitations from variations in generation output and loads) instead of static limits defined at peak times only.
- Implementing dynamic pricing options for customers with flexible CER managed by an aggregator to encourage them to shift loads and provide support in case of constraints.
- Implementing a decentralised approach for managing network capacity at a local network level.
- Offering tailored connection agreements to customers with significant flexibility in how the use the network, to reward such efficient performance.
- Using network assets and CER to dynamically manage voltage across the network.

Support the connection of new renewable generation

Ausgrid has made proposals to the Energy Corporation of NSW (EnergyCo) to upgrade the transmission network in the Hunter – Central Coast REZ (HCC REZ), to enable the connection of up to 1GW of renewable generation capacity and large-scale battery storage systems.

Proposals will also be submitted to EnergyCo to participate in the New England REZ, with transmission network solutions to unlock opportunities to transport renewable energy to consumers locally and other regions across NSW.

Source: https://www.energyco.nsw.gov.au/renewable-energy-zones

1.3 Providing efficient infrastructure

Significant investments in the transmission and distribution network are required to connect large scale renewable generation and batteries to the grid.

Long timeframes are required to deliver such large investments. Land acquisition and easements, planning and environmental approvals, equipment procurement and installation works are expected to take multiple years or even decades. Most large-scale projects in the transmission network may not be commissioned before 2030.

Distribution networks are key to achieve a cost-effective transition to net zero. Upgrades and augmentations can be made in the short to medium term to host renewable sources and better exploit available capacity of distribution networks.

Ausgrid is proposing a combination of transmission and distribution infrastructure that supports renewables by storing capacity when renewables are generating and dispatching electricity otherwise.

There is considerable potential to firm up solar generation in urban areas given the high density of solar PV installations expected, by:

- Installing 50kW/65kWh batteries on poles and 250kW/500kWh batteries connected in the low voltage network.
- Installing 5MW / 10MWh batteries with small footprint in public spaces or within substations
- Installing 100MW / 200MWh batteries adjacent to large substations. This may avoid the need to acquire additional land and/or easements, which in turn reduces community impacts.

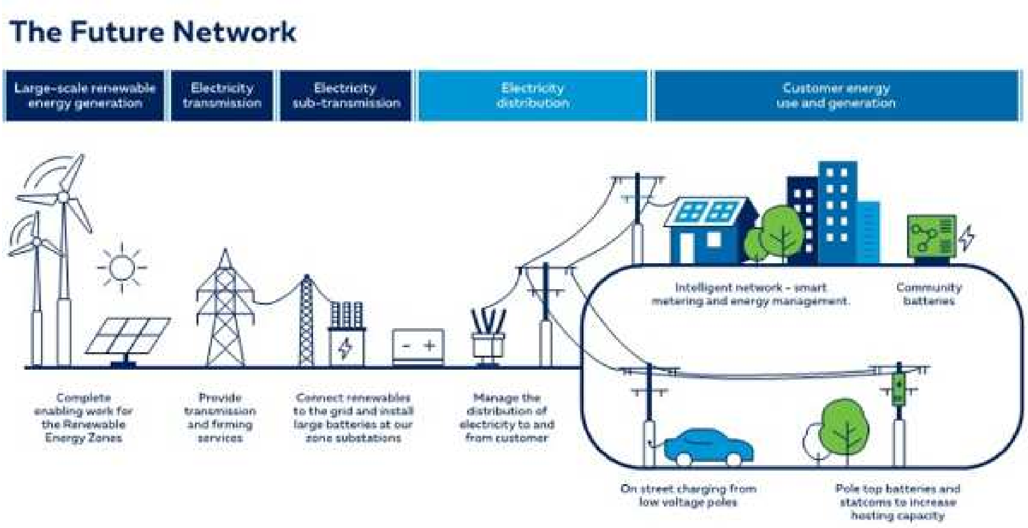
The distribution network can host and better exploit available capacity in the middle of the day. Ausgrid will seek opportunities to get the most of batteries located in distribution networks. Economies of scale can be achieved in this area.

The deployment of smart meters will also contribute to bring material benefits to residential and small business customers.

With the combination of this infrastructure and tariff incentives, a solar customer would be able to export surplus power to the community battery without paying transmission and distribution charges, and in exchange for that be able to import power from the battery without paying transmission and distribution charges.

This will make access to energy storage more equitable for customers who cannot afford behind-the-meter batteries, are renting, or live in an apartment building. They may also provide energy support for essential services during emergencies.

Significant progress can be made in providing these options to small customers within the next five years.



1.4 Providing an affordable service

Affordability is becoming an increasing challenge, primarily due to factors outside our control:

- Escalating expenses driven by inflation and surging interest rates;
- The potential effect of added investment in transmission and generation costs on energy bills; and
- Balancing the delivery of net zero with affordable electricity for all customers.

Our goal is to reduce network expenditure and enhance customer affordability, all while facilitating a smooth transition for customers towards cleaner energy alternatives. To achieve this, Ausgrid will work on:

- Equitable net-zero transition for all customers, by making investments that extend benefits to those who live in apartments, social housing or rented properties.
- Reducing the need for traditional network upgrades, by implementing coordinated management of CER, at a scale that can help reduce network constraints.

Ways to improve affordability

Ausgrid is committed to:

- Reduce operating expenditure utilising a productivity target in our proposed operating cost allowance.
- Apply risk management to make prudent investment decisions on our network assets.
- Reduce Regulatory Asset Base (RAB) value per customer over the coming years in real terms. This includes the capital expenditure required to deliver a safe/reliable supply, better customer experience and net zero, as well as the operating expenditure to support our operations.

Value for our community

Amplify Value

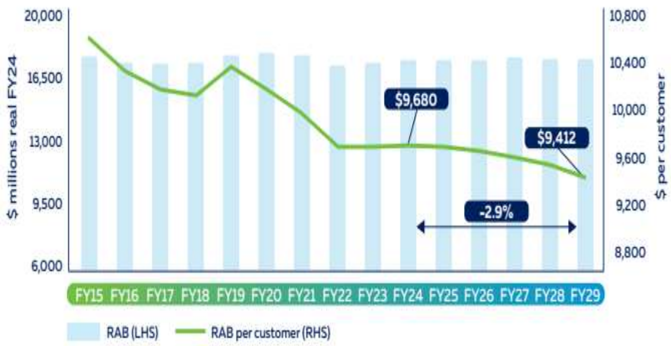
- Delivering value-for-money services to grow our asset base, meet stakeholder expectations and enhance our value proposition.

Powering Progress

- Increase grid capacity and improve asset management resilience strategies.
- Drive technology advancements and operational efficiency for revenue growth.

Stakeholder Synergy

- Foster stakeholder engagement to secure investment for improving grid services while maintaining focus on high-value, aligned opportunities.



RAB Value and RAB Value per customer

In terms of tariffs:

- Since July 2022, Ausgrid has been trialling innovative tariffs for 2-way energy flows, flexible loads and community batteries.
- From July 2024, Ausgrid will introduce export pricing with both a charge and a reward component, giving CER customers incentives to adjust the timing of their energy exports to reduce costs and increase the benefits of their exports for themselves, as well as for the whole energy system

Risk-Based Approach Investments to support our governance processes

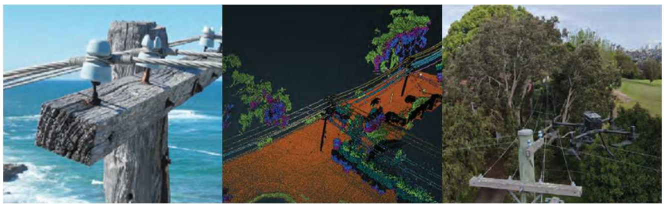
Our evaluation and governance approaches are industry best practice. to deliver an efficient and reliable operation, meeting regulatory obligations and the needs of customers.

- We have tools capable of analysing network assets performance, to support optimised decisions from a life cycle perspective.
- We apply a sustainable level of investment that prevents current and future customers facing materially different levels of costs and risk.
- Post-implementation reviews are conducted to continually learn and improve our asset management strategies.

1.5 Continuing the path to digitisation

Streamlining our core Information Communications and Technology (ICT) platforms is crucial for delivering faster and more efficient services. Digital advancements offer opportunities to enhance service delivery, provide innovative service offerings, and simplify customer interactions. Our aim is to improve customer experience, including enhancing outage information, simplifying connection processes, and supporting delivery partnerships. To achieve this, we plan to:

- Empower customers with more choice and ability to manage their energy costs;
- Offer high quality personalised support;
- Enhance how we share data with our delivery partners, to enable more seamless interactions and smoother service delivery to our mutual customers, and in turn develop a coordinated approach for building consumer trust in the energy sector; and
- Automate manual processes to reduce errors, save time and resolve customer issues more quickly.



- Smart meter data – Used to assess solar hosting capacity, monitor and resolve power quality issues and identify network issues.
- Drone technology - Employing drones alongside helicopters to conduct bushfire safety checks on the network.

A cyber-safe digital transformation is critical to keep pace with customers' evolving service expectations while delivering efficiently for customers.

Cyber resilience

- Increasing frequency and sophistication of cyber-attacks pose
- risks to network reliability and customer data. In 2021, Australia experienced a cyber-attack every eight minutes (source: ACSC).
- Growing digital footprint and device connectivity amplify potential consequences of cyber threats.
- A catastrophic cyber-attack on our network (which includes Sydney CBD) would have social, economic, health and even geopolitical ramifications for Australia.
- Balancing advanced customer experience with a secure network and robust cybersecurity measures is a priority.
- To manage cyber threats, NSW regulations mandate 'best industry practice' for limiting network and ICT systems to be accessed, operated and controlled from within Australia.
- Ausgrid is actively aligning safeguards with industry standards and complying with amended Commonwealth Security of Critical Infrastructure Act 2018 requirements.

How we manage cyber security

- Our Control System Security Strategy safeguards the operational technology of our electricity network and is regularly refined for best practice alignment.
- Ausgrid strengthens cyber resilience through staff education, a rigorous vulnerability management program and implementing multiple layers of defence.
- We delivered upgrades of Electronic Access Control Management Systems and video surveillance system technology at Ausgrid substation, depot and corporate sites to bolster physical and personnel safety.
- We conducted 'see something, say something' and 'site secure habit' awareness sessions across the business.

2. Network Investments

2.1 RIT-D assessments completed and in progress

The following Regulatory Investment Tests for Distribution (RIT-D) have been completed in the preceding year.

Region	Constraint	Project Name	Expected Project Completion	Estimated Cost ($m)	RIT-D completion date
Sydney	*Load Growth*	*11kV augmentation in the Circular Quay load area*	*Dec-2024*	*15.0*	*20/08/2023*
	Asset Condition	*132kV feeders 9SA & 92P replacement & Loop Zetland ZS into feeder 92P*	Sep-2025	*37.1*	*12/01/2023*
	Asset Condition	*132kV feeders 923 & 924 Strathfield TP-Burwood ZS replacement*	*Sep-2025*	*13.2*	*24/02/2023*
	Load Growth	*New Macquarie STS Transformer 3*	*Dec-2025*	*7.4*	*30/04/2023*
	Asset Condition	*Milperra ZS 11kV switchgear replacement*	*Jun-2026*	*13.2*	*31/05/2023*
	Asset Condition	*Mascot ZS 11kV switchgear replacement*	*Jun-2026*	*12.3*	*05/11/2023*

A summary is provided to describe the identified need Ausgrid is seeking to address, outline the credible network options considered, explain why other network options were not pursued, identify the proposed preferred option, and explain the reasons for its selection. In addition, the summary includes the corresponding dates in which the different steps of the RIT-D process were completed.

Cost estimates are reported in real dollars. The corresponding reports for this RIT-D assessment are available in Ausgrid's website at the following link: [Regulatory investment test projects - Ausgrid]

2.1.1 11kV augmentation in the Circular Quay load area

The Circular Quay network area is part of Ausgrid's 11 kV Sydney CBD network that serves customers in the area bounded between Barangaroo, Sydney Harbour, Darling Harbour, Central Railway Station and the Domain. The Sydney CBD is the commercial heart of Sydney and contains a significant concentration of office buildings, commercial businesses and apartments that all use substantial amounts of electricity. The peak demand for the Sydney CBD area is currently approximately 350 MVA in the summer, driven predominantly by air-conditioning.

The Sydney CBD load area is currently served by six ZS, the oldest two of which are in the process of being decommissioned.

Sydney CBD ZS are supplied via Transgrid's Haymarket bulk supply point (BSP) and the Beaconsfield BSP, together with Ausgrid's Inner Metropolitan Transmission network that includes supply from Rozelle and Lane Cove sub-transmission substation (STSS).

Ausgrid is currently in the process of decommissioning the Dalley St ZS and City East ZS due to deteriorating condition issues associated with assets reaching the end of their serviceable lives. Specifically:

- Dalley St ZS utilises aging compound filled insulted switchgear that has exhibited poor performance including failure. Further, many other components in the substation are reaching the end of their serviceable lives and consist of obsolete technology, increasing the difficulty of remediation in event of failure; and
- City East ZS utilises obsolete oil and bitumen insulated technology and the substation is exposed to fire-related risk in the event of failure.

Two different network credible options have been identified:

- Option 1 - Construct three new circuits at the City North ZS in the vicinity of George and Alford Streets to cater for loads on Pitt Street. The estimated capital cost of this option is approximately $15 million, and the weighted net economic benefit was estimated to be $447.5million.
- Option 2 - Construct two new circuits initially (followed by a third circuit later if required). The estimated capital cost of this option is approximately $13.1 million, and the weighted net economic benefit was estimated to be $447.2 million.

Ausgrid has considered the ability of any non-network or SAPS solutions to assist in meeting the identified need. An assessment into reducing the risk of expected unserved energy (EUE) has shown that these alternatives are unlikely to cost-effectively address the risk, compared to the two network options outlined above. This result is driven primarily by the significant amount of EUE that each network option allows to be avoided, compared to the base case, and the cost of non-network or SAPS solutions.

Ausgrid considers that Option 1 is the preferred option that satisfies the RIT-D. It involves the construction of three new circuits connected to City North ZS in the vicinity of George and Alford Streets to supply newly connected customers and additional committed loads in the Circular Quay area. This option involves the simultaneous installation of three circuits to meet future customer load forecasts.

A Final Project Assessment Report (FPAR) was published on 21 July 2023, presenting the assessment undertaken. A separate non-network screening notice was also released outlining that for this RIT-D, non-network solutions were unable to form a standalone credible option or form a significant part of a potential credible option.

The 30-day dispute period ended on 20 August 2023 and no enquiries/disputes were received.

Construction work will commence in the second half of FY23 following completion of project approvals. Electrical load transfers and commissioning is expected to be completed in FY25.

2.1.2 132kV feeders 9SA & 92P replacement & loop Zetland ZS into feeder 92P

The underground electricity subtransmission cables ('feeders') supplying the Eastern Suburbs load area include self-contained fluid filled (SCFF) feeders, which are now considered an obsolete and outdated technology. They are becoming less reliable and approaching the point at which their replacement maximises the net benefit for the community. Ausgrid has made a commitment to the NSW Environment Protection Authority (EPA) to a program of replacing or retiring all SCFF cables with known leaks by 2034, due to the environmental risks associated with oil leaking from these cables (as well as the associated decline in network reliability).

Feeders 260, 261, 9SA and 92P (which supply the Zetland and Waterloo load areas as well as some portions of the Eastern Suburbs load area) are all ranked in the group of SCFF feeders to be replaced or retired as a priority, being high or medium risk feeders.

Ausgrid has identified the need to mitigate risks associated with 132kV feeders 260 and 261, which run from Beaconsfield Supply Point (BSP) to Zetland Zone Substation (ZS). If action is not taken, planning studies indicate that there will be EUE to loads in this area of the network if these cables fail, as well as reactive maintenance costs associated with having to repair and restore service, and environmental risks from oil leaking from the cables. Without action, Ausgrid may breach our electricity distribution license reliability and performance standards.

Ausgrid has also identified 132kV feeders 9SA and 92P as a high priority for replacement with modern technology cables, because of the environmental risks associated with potential oil leaks from these cables. Feeders 9SA and 92P run from the Beaconsfield BSP to Campbell St ZS and Belmore Park ZS respectively. They are key feeders that form part of Sydney's Inner Metropolitan Subtransmission network. Due to their geographic proximity, addressing concerns associated with feeders 9SA and 92P at the same time as replacing feeders 260 and 261 offers cost efficiencies when compared to addressing them in isolation.

Three different network credible options have been identified:

- Option 1 – Replace the existing feeders 9SA, 92P, 260 and 261 like-for-like using modern equivalent technology. The estimated capital cost of this option is approximately $52.2 million, and the weighted net economic benefit was estimated to be $11.0 million.
- Option 2 – Replace SCFF sections of feeders 9SA and 9SP, loop Zetland ZS into feeder 92P and close Zetland 132kV busbar. The estimated capital cost of this option is approximately $40.7 million, and the weighted net economic benefit was estimated to be $9.7 million.
- Option 3 – Replace SCFF sections of feeders 9SA and 92P, loop Zetland ZS into feeder 92P and defer works on closing Zetland 132kV busbar. The estimated capital cost of this option is approximately $37.1 million, and the weighted net economic benefit was estimated to be $14.0 million.

Ausgrid has considered the ability of any non-network or SAPS solutions to assist in meeting the identified need, reporting that such solutions were not viable for this particular RIT-D. The DPAR was accompanied by a separate non-network screening notice that provided further detail on this assessment.

Option 3 is the preferred option that satisfies the RIT-D. It involves the decommissioning of feeders 260 and 261. This is achieved by replacing 132kV SCFF sections of cable in 9SA and 92P as well as reconfiguration of feeder 92P to form feeders 92P and 9CY, each with a rating of 230MVA. Feeders 92P and 9CY will be connected into the Zetland ZS and 9SA will remain connected between the Beaconsfield BSP and the Campbell Street ZS. Once installed, the existing SCFF feeders will be decommissioned. Under this option, the necessary closing of the 132kV busbar at Zetland is deferred until 2034/35.

A Final Project Assessment Report (FPAR) was published on 13 December 2022, presenting the assessment undertaken. A separate non-network screening notice was also released outlining that for this RIT-D, non-network solutions were unable to form a standalone credible option or form a significant part of a potential credible option.

The 30-day dispute period ended on 12 January 2023 and no enquiries/disputes were received.

Construction work will commence in the second half of FY23 following completion of project approvals. Electrical load transfers and commissioning is expected to be completed in late 2025.

2.1.3 132kV feeders 923 & 924 Strathfield TP-Burwood ZS replacement

Feeders 923 and 924 are part of Ausgrid's Inner West network, supplying the Burwood load area of approximately 27,000 customers. These 132kV feeders connect the Burwood Zone Substation (ZS) to the Mason Park subtransmission switching station (STSS), via the Strathfield Transition Point (TP). The feeders include underground sections of self-contained fluid filled (SCFF) cable, which are considered an obsolete and outdated technology. They are becoming less reliable and approaching the point where their replacement maximises the net benefit for the community.

Ausgrid has identified the need to replace the underground SCFF sections of feeders 923 and 924. If action is not taken, EUE will occur if the cables fail. In addition, increasing maintenance costs to repair and restore service would be expected, as well as increasing environmental risks of oil leaking from the cables. Without action, it is expected that electricity distribution reliability and performance standards will be breached. Therefore, Ausgrid is undertaking a RIT-D to assess options for addressing the risk that the ageing SCFF sections of feeders 923 and 924 pose and to ensure reliability and performance standards are met.

Two different network credible options have been identified:

- Option 1 – Like-for-like replacement of SCFF sections of feeders 923 and 924 in existing route using modern equivalent technology. The estimated capital cost of this option is approximately $15.3 million, and the weighted net economic benefit was estimated to be $18.4 million.
- Option 2 – Replacement of SCFF sections of feeders 923 and 924 in alternative route using modern equivalent technology.

The estimated capital cost of this option is approximately $13.2 million, and the weighted net economic benefit was estimated to be $19.8 million.

Ausgrid has considered the ability of any non-network or SAPS solutions to assist in meeting the identified need, reporting that such solutions were not viable for this particular RIT-D. The DPAR was accompanied by a separate non-network screening notice that provided further detail on this assessment.

Option 2 is the preferred option that satisfies the RIT-D. It involves the commissioning of new underground feeders using modern equivalent XLPE technology between the Burwood ZS and Ismay Reserve, as well as the decommissioning of the existing SCFF feeders, the Strathfield Transition Point and removal of 230 metres of overhead lines.

A Final Project Assessment Report (FPAR) was published on 25 January 2023, presenting the assessment undertaken. A separate non-network screening notice was also released outlining that for this RIT-D, non-network solutions were unable to form a standalone credible option or form a significant part of a potential credible option.

The 30-day dispute period ended on 24 February 2023 and no enquiries/disputes were received.

Construction work will commence in the second half of FY23 following completion of project approvals. Electrical load transfers and commissioning is expected to be completed in late 2025.

2.1.4 New Macquarie STS Transformer 3

The Macquarie 132/33kV STS is in the Carlingford area of Ausgrid's network. It was commissioned in July 2021 to assist with providing supply to three major customers who were ready to connect at the time.

Two new connection applications from major customers have since been received. Both have requested secured "N-1" supply. The existing spare capacity at the Macquarie 132/33kV STS (i.e., approximately 9MVA) is not sufficient to support the connection of these two new loads.

Ausgrid considers that additional major customer loads are most efficiently met by installing a third 120MVA 132/33kV transformer unit at the Macquarie 132/33kV STS. These two major customers have both committed to make a direct contribution to the investment, to facilitate the timing of the expansion of the STS being brought forward.

As these major customers are expected to utilise nearly 90% of the asset capacity, specific tariff arrangements will be established to recover the majority of the cost of the augmentation from the beneficiaries (i.e. the new major customers), taking into account their share in the capacity added to the network.

Further network investment would be required to accommodate any additional major loads in the Macquarie Park area, as there are site limitations on adding any further transformers at the Macquarie STS. Any further investment would be considered as part of a separate RIT-D process.

Three different network credible options have been identified:

- Option 1 – Install a new transformer in 2029. The estimated capital cost of this option is approximately $9.1 million, and the weighted net economic benefit was estimated to be $12.7 million.
- Option 2 - Install a new transformer in 2026 (with capital contribution). The estimated capital cost of this option is approximately $7.4 million, and the weighted net economic benefit was estimated to be $13.0 million.
- Option 3 - Install a new transformer in 2026 (without capital contribution). The estimated capital cost of this option is approximately $8.7 million, and the weighted net economic benefit was estimated to be $12.1 million.

Ausgrid has considered the ability of non-network and SAPS solutions to assist in meeting the identified need. Specifically, an analysis of non-network options and SAPS considered how demand management could defer the timing of the preferred network solution and whether the estimated EUE at risk could be cost effectively reduced. An assessment of demand management options has shown that non-network alternatives would not be cost effective due to the magnitude of the load reduction required.

Option 2 is the preferred option that satisfies the RIT-D. It also involves installing a new 120MVA 132/33kV transformer at Macquarie STS at an estimated cost of $8.7 million, with a direct contribution from the two major customers of $1.3 million, reducing the effective capital cost to $7.4 million.

A Final Project Assessment Report (FPAR) was published on 31 March 2023, presenting the assessment undertaken. A separate non-network screening notice was also released outlining that for this RIT-D, non-network solutions were unable to form a standalone credible option or form a significant part of a potential credible option.

The 30-day dispute period ended on 30 April 2023 and no enquiries/disputes were received.

Construction work will commence in the second half of 2023 following completion of project approvals. Commissioning is expected to be completed in late 2025.

2.1.5 Milperra ZS 11kV switchgear replacement

The Milperra Zone Substation (ZS) is located in the Canterbury Bankstown network area and was commissioned in 1966. The substation serves approximately 9,500 customers including Bankstown-Lidcombe hospital, Western Sydney region TAFE, and Sydney Water Corporation. It is supplied by two underground 132kV feeders from Sydney South Bulk Supply Point (BSP) via Revesby ZS and comprises two 132/11kV 50MVA transformers, one compound insulated 11kV switchboard, and one air insulated 11kV switchboard in a double bus arrangement.

The main issue for the Milperra ZS relates to asset condition, reliability and safety concerns stemming from the compound insulated switchboard, which is beyond its design life. If no corrective action is taken, planning studies indicate the potential for EUE at Milperra ZS, as well as safety risks and reactive maintenance costs associated with repairs in the event of equipment failure. Market benefits are expected to arise from taking action to avoid this EUE. Further, we expect that our electricity distribution license reliability and performance standards would be breached based on the amount of EUE calculated at Milperra ZS if action is not taken.

Only one credible network option has been identified, which is the replacement of the existing 11kV switchgear in an extended switchroom. The scope of this project includes:

- extension of the current switchroom building to accommodate the replacement 11kV switchgear;
- installation of a new 11kV switchboard including four sections of single bus switchgear and 21 11kV circuit breakers;
- installation of 11kV connections to transfer the load from the existing 11 kV feeders to the new switchboard;
- secondary system upgrades; and
- decommissioning of the 11kV compound insulated switchboard from the site.

The estimated capital cost of this option is approximately $13.2 million, and the weighted net economic benefit was estimated to be $6.5 million.

A Draft Project Assessment Report (DPAR) was published on 3 March 2023, presenting the assessment undertaken. A separate non-network screening notice was also released outlining that for this RIT-D, non-network solutions were unable to form a standalone credible option or form a significant part of a potential credible option.

The DPAR called for submissions from parties by 14 April 2023 and no submissions were received on either the DPAR or the separate non-network screening notice. A Final Project Assessment Report (FPAR) was then published on 1 May 2023, re-presenting the assessment undertaken in the DPAR. The 30-day dispute period ended on 31 May 2023 and no enquiries/disputes were received.

Construction work will commence in the second half of 2023 following completion of project approvals. The replacement of the 11kV switchgear is expected to be completed in mid-2026.

2.1.6 Mascot ZS 11kV switchgear replacement

The Mascot 33/11kV Zone Substation (ZS) is located in the Eastern Suburbs network area and was commissioned in 1946. The substation serves over 7,000 residential and industrial customers, including the Qantas Corporate Precinct and the Equinix Data Centre.

Mascot ZS comprises three groups of 11kV compound insulated switchgear and two groups of 11kV air insulated switchgear configured in a double bus arrangement. There are increasing reliability and safety risks associated with the aging compound insulated 11kV switchgear at Mascot ZS. The three groups of compound-insulated switchgear consist of Bulk Oil Circuit Breakers (OCBs), which have been in service for over 75 years.

If no corrective action is taken, our planning studies (based on predictive failure modelling) indicate expected EUE at Mascot ZS, as well as safety risks and repair costs in the event of equipment failure. Further, reliability performance standards would be put at risk if action is not taken at Mascot ZS.

Three different network credible options have been identified:

- Option 1 – Establish a new Mascot East ZS. The estimated capital cost of this option is approximately $45.3 million, and the weighted net economic benefit was estimated to be $98.7 million.
- Option 2 – Replace compound insulated switchgear with modern equivalent technology. The estimated capital cost of this option is approximately $12.3 million (near tern) and $20.1 million (future replacement), and the weighted net economic benefit was estimated to be $122.4 million.
- Option 3 – Retire compound insulated switchgear at Mascot ZS. The estimated capital cost of this option is approximately $11.4 million (near tern) and $19.5 million (future replacement), and the weighted net economic benefit was estimated to be $119.6 million.

The ‘near term’ costs for Option 2 and Option 3 cover the compound insulated switchgear works, which are the subject of this RIT-D.

The later ‘future replacement’ costs cover replacing the air insulated 11kV switchgear and the 33kV sub-transmission cables (both of which do not currently need replacing) in future under Options 2 and 3. These later costs have been included in the costs for these two options to enable a ‘like-for-like’ comparison with Option 1, which effectively replaces all assets upfront.

Ausgrid has considered the ability of any non-network or SAPS solutions to assist in meeting the identified need. An assessment into reducing the risk of EUE has shown that these alternatives are unlikely to cost-effectively address the risk, compared to the network options outlined above. This result is driven primarily by the significant amount of EUE that each network option allows to be avoided, compared to the base case, and the cost of non-network or SAPS solutions.

Option 2 is the preferred option that satisfies the RIT-D. It involves the replacement of the existing 11 kV compound-insulated switchgear at Mascot ZS with modern equivalent switchgear.

A Final Project Assessment Report (FPAR) was published on 6 October 2023, presenting the assessment undertaken. A separate non-network screening notice was also released outlining that for this RIT-D, non-network solutions were unable to form a standalone credible option or form a significant part of a potential credible option.

The 30-day dispute period ended on 5 November 2023 and no enquiries/disputes were received.

Construction work will commence in the first half of 2024 following completion of project approvals. Commissioning is expected to be completed in mid-2026.

2.2 RIT-D assessments for the forward planning period

This section describes the network investments for which a RIT-D assessment is expected to be initiated within the next five years.

Region	Constraint	Project Name	Expected Project Completion	Estimated Cost ($m)	Indicative RIT-D initiation
Distribution Assets					
Sydney	Asset Condition	Blakehurst ZS 33kV feeders rearrangement	Mar-2027	14.5	FY25
Sydney		Pymble ZS 11kV switchgear replacement	Sep-2027	15.6	FY25
Sydney		Willoughby STS 33kV switchgear replacement	Sep-2027	22.7	FY25
Hunter	Power Quality	Installation of new Static Compensation at Waratah STS	Sep-2027	8.1	FY26
Sydney	Asset Condition	Darlinghurst ZS decommissioning	Mar-2028	16.6	FY26
Hunter		Merewether STS 33kV switchgear replacement	Sep-2028	28.9	FY26
Sydney		Botany ZS 11kV switchgear replacement	Sep-2029	8.7	FY26
Sydney		132kV feeder 202 Rozelle STS-Drummoyne ZS replacement	Sep-2029	17.7	FY26
Sydney		132kV feeders 203 & 204 Mason Pk STSS-Drummoyne ZS replacement	Sep-2029	49.7	FY26
Sydney		Drummoyne ZS 132kV switchgear replacement	Sep-2029	17.6	FY26
Sydney		Lidcombe ZS 11kV switchgear replacement (Group 1)	Sep-2030	15.1	FY27
Sydney		Paddington ZS 33kV feeders replacement	Mar-2031	10.3	FY28
Dual Function Assets					
Sydney	Asset Condition	132kV Feeders 92X and 92C Chullora STSS – St Peters ZS, 91X/2 and 91Y/2 Chullora STSS – Marrickville ZS retirement	Sep-2028	6.7	FY28
	Load Growth	New Wallumatta STS & 132kV Feeders (Contingent Project)	Dec-2028	131.4	FY25
	Asset Condition	132kV Feeders 91A & 91B Beaconsfield BSP to St Peters ZS	Sep-2029	20.2	FY28

These network investments are primarily expected to address condition issues identified in several network assets:

- Aged underground subtransmission cables, which have experienced failures and leaks.
- Aged 11kV switchgear installed in several zone substations across the network and 33kV switchgear in subtransmission substations, with insulating materials that can be a fuel source in the event of failure.
- Aged 132kV switchgear at sites with concurrent subtransmission cable replacement works.

These asset condition issues result in growing EUE that justifies replacement investments at proposed dates, with additional benefits in terms of reduction of environmental risks and repair costs.

In addition, there are large customers requesting connections in the Macquarie area, driving the need to augment the subtransmission network.

2.3 Indicative developments beyond the planning period

This section provides an overview of potential network investments in distribution and dual function network assets beyond the 5-year planning period, for which Ausgrid may initiate RIT-D assessments if the criteria are met.

Region	Constraint	Project Name	Expected Project Completion	Estimated Cost ($m)	Indicative RIT-D initiation
Distribution Assets					
Sydney	Asset Condition	Leightonfield ZS 11kV switchgear replacement	Sep-2032	8.8	2030
		Campsie ZS 11kV switchgear replacement	Sep-2032	35.0	2030
		132kV Feeder 283/2 Milperra ZS – Revesby ZS	Sep-2032	13.8	2030
Dual Function Assets					
Sydney	Asset Condition	132kV Feeder 9FF Beaconsfield BSP – Bunnerong STSS oil section replacement	Jun-2034	19.8	2031

Similar to those projects included in the previous section, these network investments are expected to address condition issues identified in aged underground subtransmission cables and 11kV switchgear equipment.

The proposed dates represent the current view of optimal timing for replacement investments, based on the latest available information on these network assets.

2.4 RIT-D assessments not proceeding

Several network needs identified in the preceding DTAPR are now not expected to proceed into network investments and/or require RIT-D assessments in the next five years. These network needs are listed in the table below.

Region	Constraint	Project	Previous Need Date	Reason for cancellation/deferral or RIT-D not proceeding
Sydney	Asset Condition	132kV Feeders 9E1 & 9E2 Sydney East-Kuringai STS oil sections replacement	2025/26	Only one credible option < $6m

2.5 Completed investments

A network investment is considered completed when the project required to address the identified network need is commissioned and in service. The following projects described in the DTPAR 2022 have been completed or cancelled during the preceding year.

Load Area	Completed Network Investments	Reason / comments
Distribution Assets		
Eastern Suburbs	Matraville ZS 11kV switchgear Groups 1, 2 and 4 replacement	Completed
Various	Community Battery Trial	Completed
Terrey Hills and Pittwater	Uprate 33kV feeders S20 & S21 overhead sections	Completed
Upper Hunter	Muswellbrook ZS refurbishment	Completed
Dual Function Assets		
Eastern Suburbs	132kV feeder 265 Bunnerong STSS-Maroubra ZS replacement	Completed

2.6 Committed investments

Ausgrid has identified all committed network investments (refurbishments, replacements, or augmentations) with an estimated capital cost of $2 million or more.

Capital cost estimates are shown in nominal dollars and exclude contingency costs.

Load Area	Committed Refurbishment, Replacement or Augmentation Investments	Expected Project Completion	Estimated Cost (nominal $m)
Distribution Assets			
Eastern Suburbs	New 33kV supply to Garden Island and decommission Graving Dock 33/11kV ZS	Dec-23	2.4
Sydney CBD	11kV Load Transfers from Dalley St ZS to City North ZS	Dec-23	18.9
Inner West	New Summer Hill 33/11kV ZS and associated 33kV feeders and decommission Dulwich Hill 33/11kV ZS	Jan-24	40.9
Inner West	Rozelle STS new 33kV switchgear	Jan-24	22.7
Inner West	Replace 33kV feeders – Homebush STS to Lidcombe ZS and Auburn ZS	Feb-24	31.3
Inner West	Lidcombe 33/11kV ZS 11kV switchgear Group 2 replacement	Mar-24	6.7
Eastern Suburbs	Decommission Darlinghurst 33/11kV ZS – Stage 1	Mar-24	3.9
Camperdown and Blackwattle Bay	Convert Blackwattle Bay load from 5kV to 11kV and load transfer and decommission 33/5kV Blackwattle Bay ZS	Jun-24	16.5
Upper Hunter	Muswellbrook STS refurbishment	Jun-24	5.6
St George	Peakhurst STS 33kV switchgear replacement	Jun-24	25.0
Eastern Suburbs	Surry Hills ZS 11kV switchgear replacement	Jul-24	18.1

Load Area	Committed Refurbishment, Replacement or Augmentation Investments	Expected Project Completion	Estimated Cost (nominal $m)
Sydney CBD	Decommissioning of City East ZS	Sep-24	44.4
Newcastle Ports	Waratah 132/33kV STS refurbishment	Dec-24	17.0
Camperdown and Blackwattle Bay	Pyrmont STS cable egress enabling works	Dec-24	2.6
Sydney CBD	Decommissioning of Dalley St ZS	Dec-24	12.5
Eastern Suburbs	Sydney Airport ZS 33kV switchgear replacement	Jan-25	7.5
Maitland	Tarro ZS 11kV switchgear replacement	Jan-25	10.7
Inner West	132kV feeders 923 & 924 Strathfield TP-Burwood ZS replacement	Sep-25	13.4
Inner West	Concord ZS 11kV switchgear replacement	Oct-25	20.0
Dual Function Assets			
Sydney CBD	Decommissioning of 132kV Feeders Lane Cove STSS – Dalley St ZS	Sep-24	3.1
Eastern Suburbs	132kV feeder 264 Beaconsfield BSP-Kingsford ZS replacement	Mar-25	23.3
	132kV feeders 9SA & 92P replacement & Loop Zetland ZS into feeder 92P	Sep-25	25.6

2.6.1 New 33kV supply to Garden Island and decommission Graving Dock 33/11kV ZS

Key project milestones:

- Project initiated in January 2019.
- Project expenditure authorised by Ausgrid Chief Executive Officer in May 2021.
- Project completion is expected by December 2023.

Options Analysis

Graving Dock ZS No.1 and No. 2 are supplied from Surry Hills 132/33kV STS, via 33kV underground feeders 377 and 378. These feeders are approximately 3km long mostly commissioned in 1946, with a section of approximately 1.3km of feeder 378 commissioned in 1930. Network investments are required due to increases in supply requirements anticipated in the area.

The only feasible solution, due to the location of the Garden Island Precinct, is to provide 33kV supply to the customer from Surry Hills STS. Other available sources of 33kV supply would require extensive and complex connections to reach the northeast of Sydney CBD.

The project was approved by the Ausgrid Chief Executive Officer on 31/05/2021, at a cost of $2.4 million excluding contingency.

2.6.2 11kV Load Transfers from Dalley St ZS to City North ZS

Key project milestones:

- Project initiated in January 2016.
- Project expenditure authorised by Ausgrid Chief Executive Officer in April 2017 (Stage 1) and January 2018 (Stage 2).
- Project completion is expected by December 2023.

Options Analysis

Ausgrid's strategic decisions for ensuring reliable supply in the Sydney CBD area arise from the need to address ageing infrastructure at City East and Dalley St ZS's. Three strategies were considered, which will address the identified risks to an appropriate degree:

Strategy 1 – New 132/11kV zone substation and decommission Dalley St and City East substations

This strategy involves establishing a new 132/11kV substation on the northern section of Sydney CBD, transferring all load at Dalley St and City East to the new zone substation and after that decommission both Dalley St and City East ZS's. The net present cost of this strategy is $165 million.

Strategy 2 – Decommission Dalley St and City East by transferring load to City North and Belmore Park substations

This strategy involves transferring approximately two thirds of the existing Dalley St ZS load to City North ZS, and all load at City East as well as the remaining load at Dalley St to Belmore Park ZS. Once completed, both Dalley St and City East substations will be decommissioned. The net present cost of this strategy is $58 million.

Strategy 3 – Refurbish existing City East ZS and decommission Dalley St ZS

This strategy involves transferring City East load to Belmore Park ZS, refurbish City East ZS at 33kV, transferring Dalley St load to the newly refurbished City East and decommission Dalley St ZS. The net present cost of this strategy is $115 million.

Strategy 2 has the lowest net present cost and is the preferred option. To capture any differences in the value of the assets remaining at the end of the planning period residual benefits were calculated for each strategy. The present value of residual benefits for Strategies 1 and 3 were $20 million compared to $10 million for Strategy 2. This difference is not material compared to the cost difference of the strategies.

As the risk of equipment failure is significant at Dalley St ZS and could result in a prolonged outage, the partial offloading of Dalley St to City North zone substation should be completed as soon as practical. Up to 65% of the load at Dalley St ZS can be transferred to City North ZS, which will substantially reduce network risks at Dalley St and enable relatively low cost recovery actions in the event of a switchgear failure.

Non-network options were considered based upon a one-year deferral value of $25/KVA and a total reduction of 50MVA required to be removed from Dalley St zone substation (65% of the load). Given the low deferral value available for reducing demand and the scale of load reduction required it was determined that non-network options could not form part of a credible option for this replacement investment.

The 11kV load transfers from Dalley St to City North ZS were initiated as a single project in January 2016. In order to reduce the impacts derived from the construction of the CBD & South East Light Rail Project, the 11kV load transfers were segmented in two stages. The two stages were presented as one project to Ausgrid Board for preliminary project approval (Gate 2 approval) because both are required to address the identified network need. The Board provided Gate 2 approval for the project in April 2016.

Stage 1 was authorised by the Chief Executive Officer on 07/04/2017 at a cost of $9.9 million ($9.0 million excluding contingency). The latest schedule review has adjusted the completion date of the project to March 2019.

Stage 2 was authorised by the Chief Executive Officer on 03/01/2018, at a total cost of $12 million ($9.9 million excluding contingency). Stage 2 was originally scheduled for completion in September 2018. This second set of load transfers have significant dependencies on the completion of the Light Rail Project, which is experiencing construction delays.

2.6.3 New Summer Hill 33/11kV ZS and decommission Dulwich Hill 33/11kV ZS

Key project milestones:

- Project initiated in March 2012.
- Project expenditure authorised by Ausgrid Board in May 2017.
- Project completion is expected by January 2024.

Options Analysis

Three strategies were considered to address issues in the Canterbury Bankstown network area. Each strategy integrates solutions to issues at Enfield, Campsie and Dulwich Hill zone substations.

Strategy 1 – Enfield 132/11kV zone substation and Dulwich Hill 33/11kV replacement

This strategy involves replacement of the existing 33/11kV Enfield with a new Strathfield South 132/11kV ZS, establishment of a new 33/11kV Dulwich Hill ZS adjacent to the existing zone site and load transfers from Campsie to Enfield to facilitate the switchgear replacement at Campsie ZS. The Net Present Cost (NPC) of this strategy was $62.2 million.

Strategy 2 – Replace Enfield and Dulwich Hill zone with new Ashbury 132/11kV zone

This strategy involves construction of a new Ashbury 132/11kV ZS and decommissioning of 33/11kV Enfield ZS and Dulwich Hill ZS by transferring all existing load to the new Ashbury ZS. This would be followed by the installation of an additional 132/11kV transformer at Ashbury ZS and load transfers from Campsie ZS to Ashbury to facilitate the switchgear replacement at Campsie ZS. The NPC of this strategy was $61.0 million.

Strategy 3 – Dulwich Hill and Enfield zone substation replacement

This strategy involves 11kV switchgear and 33kV feeder replacement at Dulwich Hill and Enfield ZS's, with the installation of an additional transformer at Canterbury STS. Another transformer would then be installed at Enfield ZS and load transferred from Campsie to Enfield to facilitate the switchgear replacement at Campsie ZS. The NPC of this Strategy was $80.1 million.

Given the low deferral value available for reducing demand and the scale of load reduction required it was determined that non-network options could not form part of a credible option for this replacement investment.

Ausgrid's preferred strategy for Canterbury Bankstown area is Strategy 1, which involves replacing Dulwich Hill Zone substation with a new 33/11kV zone substation. This strategy is preferred because:

- Strategies 1 and 2 have NPC estimates that are considered equivalent (within the level of accuracy of the estimate) and materially lower costs than Strategy 3.
- Considering the location and characteristics of loads in the area, extensive 11kV work would be required to connect all 11kV feeders to the single point of supply proposed under Strategy 2. 11kV development costs often vary greatly as a result of issues encountered during the construction phase compared to pre-project estimates. Hence, there is less uncertainty in cost estimates for Strategy 1.
- Strategy 1 provides greater system flexibility and better coverage of the surrounding 11kV networks than Strategy 2, especially for some load areas (e.g. Belfield, Strathfield and Strathfield South).

Additional investigations were carried out to determine the viability of a conversion to 132kV operation, as well as the most ideal location of the new Dulwich Hill ZS.

The conversion of Dulwich Hill to 132kV operation was rejected due to the high costs associated with achieving 132kV feeder connections. Although 132kV supply in the area is currently available via feeders 92C, 92X, 91X or 91Y, all these fluid filled cables are targeted for retirement within the next 10 years. Any other 132kV supply to connect a new 132/11kV zone substation at this location would need to originate from Chullora STSS (approximately 7km long), looping into the existing 132kV overhead feeders 910/911 via an underground connection (approximately 3km long), or an underground connection from Marrickville zone substation (approximately 4km long). In all these cases, the installation of 132kV switchgear at the Dulwich Hill end will be required.

The project was approved by Ausgrid Board on 01/05/2017, at a total cost of $43.9 million ($40.9 million excluding contingency). A prolonged development time was experienced as the scope of the project was refined to reduce project costs.

2.6.4 Rozelle STS new 33kV busbar

Key project milestones:

- Project initiated in September 2017
- Project expenditure authorised by Ausgrid Board at a meeting in March 2019
- Project completion is expected by January 2024

Options Analysis

Sydney Motorway Corporation has submitted a connection request for a supply of 38MVA for the Main Tunnel (Stage 3A) and 33MVA for the Rozelle Interchange (Stage 3B) of the proposed WestConnex motorway. WestConnex Stages 3A and 3B are both currently under construction. Westconnex Stage 3A is to be supplied from Alexandria 132/33kV STS.

Two network options were considered to supply Westconnex Stage 3B:

Option 1 – Upgrade Rozelle STS

This option includes the installation of a 33kV busbar and upgrade of one Rozelle transformer from 30MVA to 60MVA. This approach provides a diversity of supply to the Westconnex Stage 3 tunnel and will facilitate other future connections at Rozelle anticipated due to development in the Rozelle and White Bay areas. This option provides network assets close to the required connection point.

The Net Present Cost of this option was $25.7 million.

Option 2 – Expand Alexandria STS

Alexandria STS has been recently completed, and would require expansion to facilitate the additional connections. This approach would have all Westconnex Stage 3 tunnel supplies from a common source, does not address other anticipated connection requirements at Rozelle 132/33kV STS. The length of new 33kV cables would be greater with this option.

Option 2 was ultimately disregarded because the connection of additional 33kV cables may require complex civil works (i.e. underbore) due to cable access/egress issues in the underground routes at Alexandria STS. In addition, this option will not avoid the need to augment the network to accommodate future load requirements in the Rozelle area.

Ausgrid has also considered the ability of non-network solutions to assist in meeting the identified need. A demand management assessment has determined that non-network options cannot cost-effectively address the need to connect the customer loads.

The project was approved by Ausgrid Board on 15/03/2019, at a total cost of $24.2 million ($22.7 million excluding contingency).

2.6.5 Replace 33kV feeders – Homebush to Lidcombe ZS and Auburn ZS

Key project milestones:

- Project initiated in August 2014
- Project expenditure authorised by Ausgrid Board at a meeting in February 2018
- Project completion is expected by February 2024

Options Analysis

Auburn and Lidcombe ZS's are 33/11kV zone substations located in the Inner West area of Ausgrid's network. These substations are supplied by three 33kV underground feeders respectively, all of which originate at Homebush STS. The oldest sections supplying Auburn ZS date back to 1942, while most feeder sections on the other feeders were commissioned in the 1940s and 1950s. These underground subtransmission feeders are a combination of paper insulated and gas pressure cable technologies, and have reached the end of their service lives. They have a combined length of approximately 37km, from which 22km are paper insulated and the remaining 15km are gas pressure cables.

In particular, the gas pressure cables are prone to gas leakages that results in high levels of unavailability due the long time required to locate and repair leaks. While paper insulated cables do not have the same requirements of pressured gas (nitrogen) to maintain insulation integrity and therefore do not present same risks as gas pressure cables, the paper insulated cable sections have experienced a number of outages in recent years. If these issues are left unaddressed, the risk of failure and poor availability of these assets will expose customers in the Inner West network area to a network risk that exceeds allowable levels under the applicable reliability standards.

Ausgrid, working with Endeavour Energy, identified a preferred solution that makes use of spare capacity on the Endeavour network following closure of a Shell Australia oil refinery at Clyde in Western Sydney. Ausgrid considers that these joint planning efforts identified the most efficient solution across the respective networks as a whole. In particular, this solution was found to come at a significantly lower cost than rebuilding the existing feeders on a 'like-for-like' basis. In fact, the proposed solution defers upstream investments that would otherwise be required if supply of Auburn and Lidcombe ZS's were to continue to come from Homebush STS.

The proposed route from Camellia STS to Auburn ZS is mainly through industrial areas, crossing Duck Creek and the existing M4 Western Motorway by following the Duck River Cycleway. Ausgrid plans to use underground cables in certain areas in response to community feedback and to minimise risks along the M4 motorway. The overhead route between Auburn ZS and Lidcombe ZS will pass primarily through industrial areas and cross under the main western rail line at Percy Street. Ausgrid plans to locate the cables on the western side of Percy Street, on existing low voltage powerline structures to minimise construction impacts.

The project was approved by Ausgrid Board on 03/02/2018, at a total cost of $37.2 million ($31.3 million excluding contingency).

2.6.6 Lidcombe 33/11kV Zone Substation Group 2 11kV Switchgear Replacement

Key project milestones:

- Project initiated in September 2014.
- Project expenditure authorised by Ausgrid Board in December 2017.
- Project completion is expected by March 2024.

Options Analysis

The options analysis was initiated in 2013 and further reviewed in 2014 and 2015. The network options considered solutions to address condition issues with 11kV compound insulated switchgear at Lidcombe ZS and 33kV supply to both Auburn and Lidcombe zone substations. The options explored reconfiguration of the existing zone substations as well as the transition towards a 132kV supply.

These options and their corresponding (PC)in $ million are listed below:

Option Description		NPC
1	Uprate Auburn and retire Lidcombe	$68.5M
2	Auburn 132kV conversion and retire Lidcombe (not feasible)	N/A
3	Replace both Auburn and Lidcombe with a new 132/11kV zone substation	$57.8M
4	Replace 33kV feeders like-for-like and refurbish Lidcombe	$72.5M
5	Replace 33kV feeders from Homebush STS to Auburn and reconfigure Lidcombe	$58.2M
6	Replace 33kV feeders from Camellia Substation and reconfigure Lidcombe	$48.5M
7	Replace Lidcombe with new 132/11kV substation and reconfigure Auburn 33kV feeders	$51.9M
8	Replace 33kV feeders from Camellia Substation and reconfigure both substations	$42.0M

Given the low deferral value available for reducing demand and the scale of load reduction required, it was determined that non-network options could not form part of a credible option for this replacement investment.

Option 8 has the lowest NPC and the least risk. It is therefore the preferred option.

Further development of this option identified opportunities to defer the replacement of Group 1 switchgear at Lidcombe zone substation, which have been replaced with vacuum trucks. As a result, the scope and cost of the preferred option has been reduced as it considers replacing the 11kV switchgear (Group 2 only) at Lidcombe zone substation now and the remaining switchgear group later. The NPC of the enhanced Option 8 was further reduced to $40.2 million, of which $9.1 million is the contribution of replacing the 11kV compound insulated switchgear (Group 2).

This project experienced significant delays because it is developed in combination with the replacement of 33kV feeders supplying Auburn and Lidcombe zone substations. Extensive community consultation on the feeders and coordination issues with the project that involves the widening of the M4 Motorway (part of the WestConnex development) have caused such delays.

The project was approved by Ausgrid Board on 14/12/2017, at a total cost of $9.1 million ($6.7 million excluding contingency).

2.6.7 Decommission Darlinghurst 33/11kV ZS – Stage 1

Key project milestones:

- Project initiated in February 2018
- Project expenditure authorised by the Ausgrid Chief Operating Officer in June 2019 (Stage 1)
- Project completion is expected by March 2024

Options Analysis

Two network options were considered to address identified asset condition issues at Darlinghurst ZS:

Option 1 – Staged retirement by staged transfer of load

This strategy involves transferring the existing load on Darlinghurst ZS to adjacent zone substations in two stages. The first stage allows for the retirement of the highest risk switchgear with compound insulated busbars, and deferral of the remaining switchgear with air insulated busbars until a later time.

The Net Present Cost of this option was $2.8 million (Stage 1 only).

Option 2 – Single-staged retirement by transfer of all load

This strategy involves transferring all the existing load on Darlinghurst ZS to adjacent substations in one project and allows for the earlier decommissioning of Darlinghurst ZS. There is no cost deferral benefit with this approach.

Option 2 was not pursued further because it would cost three times more than Option 1 and the replacement of 11kV air insulated switchgear is not required in the short term. In addition, Option 2 does not provide a corresponding increase in benefits.

Given the low deferral value available for reducing demand and the scale of load reduction required it was determined that non-network options could not form part of a credible option for this replacement investment.

The project was approved by Ausgrid Chief Operating Officer on 27/06/2019, at a total cost of $4.2 million ($3.9 million excluding contingency).

2.6.8 Convert Blackwattle Bay load from 5kV to 11kV and load transfers to retire Blackwattle Bay ZS

Key project milestones:

- Project initiated in November 2015.
- Project expenditure authorised by Ausgrid Board in June 2017.
- Project completion is expected by June 2024.

Options Analysis

Three network options were considered to resolve the above issues:

Option 1 - Commission the 4th transformer at Camperdown zone substation and transfer Blackwattle Bay load to Camperdown zone substation

This option involves:

- 2016/17 – Surry Hills to Camperdown zone substation 11kV load transfer to facilitate 11kV switchgear replacement at Surry Hills zone substation;
- 2017 – Commission the 4th transformer and associated 33kV feeder and install 11kV switchgear at Camperdown zone substation;
- 2018 – Convert Blackwattle Bay zone substation load from 5kV to 11kV and transfer load to Camperdown zone substation; and
- Three minor 11kV load transfer projects post 2028.

The NPC of this option was $19.0 million.

Option 2 - Transfer Blackwattle Bay load to Camperdown and Darling Harbour zone substations

This option involves:

- 2016/17 – Surry Hills to Campbell St zone substation 11kV load transfer to facilitate 11kV switchgear replacement at Surry Hills zone substation;
- 2018 – Convert Blackwattle Bay zone substation load from 5kV to 11kV and transfer to Camperdown and Darling Harbour zone substations;
- 2022 - Commission the 4th transformer and associated 33kV feeder and install 11kV switchgear at Camperdown zone substation;
- 2022 – 10MVA 11kV load transfer Darling Harbour to Camperdown zone substation; and
- Three minor 11kV load transfer projects post 2027.

The NPC of this option was $20.2 million.

Option 3 – Transfer Camperdown load to Leichhardt zone substation and transfer Blackwattle Bay load to Camperdown and Darling Harbour zone substations

This option involves:

- 2016/17 – Surry Hills to Camperdown zone substation 11kV load transfer to facilitate 11kV switchgear replacement at Surry Hills zone substation;
- 2018 – 8MVA load transfer from Camperdown to Leichhardt zone substation via switching;
- 2018 – Convert Blackwattle Bay zone substation load from 5kV to 11kV and transfer load to Camperdown and Darling Harbour zone substations;
- 2020 – 4MVA 11kV load transfer from Darling Harbour to Camperdown zone substation;
- 2023 - Commission the 4th transformer and associated 33kV feeder and install 11kV switchgear at Camperdown zone substation;
- 2023 – 8MVA 11kV load transfer Darling Harbour to Camperdown zone substation; and
- Three minor 11kV load transfer projects post 2027.

The NPC of this option was $19.8 million.

Given the low deferral value available for reducing demand and the scale of load reduction required it was determined that non-network options could not form part of a credible option for this replacement investment.

The NPC results of the network options are considered equivalent given the accuracy of planning estimates. Option 3 is the recommended solution because it provides greater flexibility to address future growth in the Blackwattle Bay area, as several commercial and residential developments are likely to occur. In addition, it defers the need for the additional transformer at Camperdown zone substation.

The project was approved by Ausgrid Board on 20/06/2017, at a total cost of $18.1 million ($16.5 million excluding contingency).

The original completion date of the 11kV load transfers was September 2018, with decommissioning of Blackwattle Bay 33/5kV zone substation targeted for March 2019. Project complexities associated with staging/planning customer outages, night works and increased cable testing requirements have led to extension of the project construction timeframe.

Muswellbrook STS Refurbishment

Key project milestones:

- Project initiated in July 2016.
- Project expenditure authorised by Ausgrid Chief Executive Officer in January 2020.
- Project completion is expected by June 2024.

Options Analysis

Condition issues have been identified in the 33kV outdoor switchgear and secondary systems at Muswellbrook STS. In particular, the 33kV Essantee isolators have additional safety risks to personnel involved in switching operations. Furthermore, the 33kV oil filled circuit breakers of this age and type have a history of failures derived from degraded insulation quality. There are extensive condition issues with the existing control and protection, earthing and oil containment systems. There is also an opportunity to retire/reconfigure parts of the 33kV network after recent projects in the area have resulted in disused 33kV feeders and equipment.

One credible network option has been identified to address asset condition issues at Muswellbrook STS. It involves refurbishing Muswellbrook STS, to retire the 33kV switchgear that is redundant to the network and replace the minimum equipment to maintain 33kV supply in the area, and rearrangement of the Muswellbrook STS 33kV network.

Other options were considered but not progressed because they were not feasible. These included the retirement of Muswellbrook STS and reconfiguration of the 33kV network in the area; the retirement of both Muswellbrook STS and Muswellbrook ZS and transferral of 11kV load to Mitchell Line ZS and Aberdeen ZS, including rearrangement of the 33kV network to provide supply to mine operations and maintain back up supply to Moonan ZS and Rouchel ZS; and the establishment of a new Muswellbrook 132/33kV STS. These options were disregarded because the costs were considerably higher, noting that if both Muswellbrook STS and Muswellbrook ZS are retired, the supply capacity will be considerable reduced in the area. The connection of possible future renewable generation will pose increased technical and economic issues without Muswellbrook STS. Furthermore, the reconfiguration of the 132kV network post retirement of Muswellbrook STS will require extensive protection upgrades to achieve compliance with the National Electricity Rules.

Ausgrid has considered the ability of any non-network options to assist in addressing the risks. A demand management assessment examined the possibility of deferring the proposed network investment at Stockton ZS by either 1, 2 or 3 years. The results indicate that costs for non-network alternatives would be considerably higher than the costs of network options.

Refurbishment of Muswellbrook STS and rearrangement of the Muswellbrook STS 33kV network is the preferred option. The works will involve the retirement of a transformer and decommissioning existing 33kV switchgear and all redundant 33kV equipment at Muswellbrook STS, as well as the rearrangement of the 33kV network by dismantling redundant connections and installing new links required.

The project was approved by the Ausgrid Chief Executive Officer on 9/01/2020, at a cost of $5.6 million excluding contingency.

2.6.9 Peakhurst STS 33kV switchgear replacement

Key project milestones:

- Project initiated in November 2016
- Project expenditure authorised by Ausgrid Board at a meeting in December 2018
- Project completion is expected by June 2024.

Options Analysis

Two network options were considered to address the asset condition issues with the 33kV switchgear and switch building at Peakhurst STS:

<u>Option 1 – Replacement of 33kV switchgear in new building</u>

This option involves construction and equipping of a new 33kV switch building within the existing STS site.

The Net Present Cost of this option is $26.5 million (with 10% risk).

<u>Option 2 – Replacement of 33kV switchgear in existing building</u>

This option involves a staged replacement of the 33kV switchgear in the existing switch building, in conjunction with the refurbishment of the building which has structural and roofing problems.

The Net Present Cost of this option is $26.6 million (with 40% risk).

Option 1 is the preferred option. The estimated costs of each option are similar, however, the cost estimate for Option 2 has much more uncertainty due to the risks and unknowns associated with working in a “brownfield” situation, working around existing live equipment. Option 2 also has increased complexity in staging and longer outage requirements with increased risk of interruptions to customers.

A demand management assessment into reducing the risk of EUE from the 33kV feeders showed that non-network alternatives cannot cost-effectively address the risk, compared to the two network options outlined above.

The project was approved by Ausgrid Board on 17/12/2018, at a total cost of $26.8 million ($25.0 million excluding contingency).

2.6.10 Surry Hills 11kV switchgear replacement

Key project milestones:

- Project initiated in June 2011.
- Project expenditure authorised by Ausgrid Board in February 2015.
- Project completion is expected by July 2024.

Options Analysis

Three network options were considered to address identified issues at Surry Hills ZS:

Option 1 – Retire Surry Hills zone substation via 11kV load transfers to surrounding zone substations

Campbell St is the only zone substation near Surry Hills with significant spare capacity and potential for expansion; however, even if augmented to its potential three-transformer arrangement it will not have enough spare capacity to absorb the load required to allow full retirement of Surry Hills ZS. Campbell St ZS is forecast to have insufficient spare capacity at the end of the planning period in its augmented arrangement to accommodate the entire Surry Hills ZS load.

This option is therefore not considered technically feasible.

Option 2 – New Surry Hills zone substation

Surry Hills ZS is located in a dense urban area with narrow, busy streets and sensitive residents and businesses. As such, an appropriate site for a replacement zone for Surry Hills would likely be prohibitively expensive. Egress of transmission and distribution cables would likely be difficult, and the cost of transferring load from the old zone to the new zone would likely be more than replacing the switchgear in the existing Surry Hills switch-room. This option would not only resolve issues with the 11kV switchgear, but also resolve condition issues with the 33kV gas pressure cables supplying Surry Hills ZS.

The estimated cost of this option is $43 million. The Net Present Cost of this option was $39 million.

Option 3 – Replace Surry Hills 11kV switchgear and 33kV feeders

In this option, 11kV load is to be transferred from Surry Hills ZS to Campbell St and Camperdown zone substations, allowing staged replacement of the aged 11kV switchgear with fixed-pattern single bus switchgear. The 33kV feeders from Surry Hills STS to Surry Hills ZS would be replaced with modern equivalent technology by 2024.

The Net Present Cost of this option was $25 million.

Given the low deferral value available for reducing demand and the scale of load reduction required it was determined that non-network options could not form part of a credible option for this replacement investment.

Option 2 is significantly more expensive than Option 3, and Option 1 is not technically feasible. As a result, the proposal to replace Surry Hills ZS 11kV switchgear and 33kV feeders (Option 3) is shortlisted as the preferred solution.

The project was approved by Ausgrid Board on 25/02/2015, at a total cost of $19.1 million ($18.1 million excluding contingency).

2.6.11 Decommissioning of City East St ZS

Key project milestones:

- Project initiated in October 2016.
- Project expenditure authorised by Ausgrid Board in October 2018.
- Project completion is expected by September 2024.

Refer to Item 2.6.2 above for an explanation of the options analysis, the proposed strategies and the selection of the preferred option.

The project was approved by the Ausgrid Board on 29/10/2018, at a total cost of $44.4 million ($42.4 million excluding contingency).

2.6.12 Waratah 132/33kV STS refurbishment

Key project milestones:

- Project initiated in April 2010.
- Project expenditure authorised by Ausgrid Board in March 2016.
- Project completion is expected by December 2024.

Options Analysis

The 33kV industrial busbar at Waratah STS is significantly aged and needs to be retired from service. The 33kV domestic busbar was refurbished in the 1980s but the oil circuit breakers now require replacement. Four out of seven of the 132/33kV transformers are at the end of their service lives.

Two options have been considered to address issues with Waratah STS:

Option 1 – Waratah STS supply rearrangement and refurbishment

This option involves removing all loads, except major customers, from the Waratah domestic busbar. All unused equipment at Waratah STS is to be decommissioned, including four transformers and three sections of 33kV busbars.

In addition, neighbouring zone substations Mayfield, Shortland and Wallsend and Kooragang West switching station are to be decommissioned with all loads to be transferred to new substations recently commissioned or about to be commissioned.

The estimated cost for this option is $19.8 million.

Option 2 – Waratah STS replacement

This option proposes constructing a new 132/33kV substation on a nearby site and decommissioning the existing Waratah subtransmission substation.

In addition, neighbouring zone substations Mayfield, Shortland and Wallsend and Kooragang West switching station are to be decommissioned with all load is to be transferred to new substations recently commissioned or about to be commissioned.

The estimated cost for this option is $44.3 million.

Given the low deferral value available for reducing demand and the scale of load reduction required it was determined that non-network options could not form part of a credible option for this replacement investment.

The preferred option is Option 1 as it is the least cost option.

The project was approved by Ausgrid Board on 30/03/2016, at a total cost of $18.1 million ($ 17.0 million excluding contingency).

2.6.13 Pyrmont STS 33kV cable enabling works

Key project milestones:

- Project initiated in July 2017.
- Project expenditure authorised by Ausgrid Chief Executive Officer in July 2021.
- Project completion is expected by December 2024.

The existing Pyrmont STS cable corridor is extremely congested due to the high number of cables originating from the site, particularly to the south of the substation. This results in limited space within the roadway to install additional cables.

In anticipation of future major customer connections or replacement projects, additional new 33kV route corridors are required, installed in such way as to avoid any further mutual heating and de-rating of the existing cables, as well as ensuring reliable electricity supply.

Options Analysis

The only feasible solution, due to the location of these major customers, is to enable the provision of 33kV supply from Pyrmont STS. Other available sources of 33kV supply would require extensive and complex connections arrangements.

One of the prospective customers is proceeding with its connection application to receive additional 33kV supply from Pyrmont STS. This triggers an opportunity for efficient delivery of the ducts Ausgrid requires by funding an addition to the scope of the customer funded work. In practical terms this consists of including additional Ausgrid ducts in the customer excavation and sharing the costs in proportion to the number of ducts.

A similar future conduit installation works performed by Ausgrid in the vicinity of Pyrmont STS would be considerably more expensive (i.e. likely to be more than double the costs of the works proposed in this approval), with a higher degree of complexity (i.e. tunnel works) and likely result in Pyrmont STS being underutilised.

The project was approved by the Ausgrid Chief Executive Officer on 23/07/2021, at a cost of $2.6 million excluding contingency.

2.6.14Decommissioning of Dalley St ZS

Key project milestones:

- Project initiated in August 2020.
- Project expenditure authorised by the Ausgrid Board in August 2022.
- Project completion is expected by December 2024.

Refer to Item 2.6.2 above for an explanation of the options analysis, the proposed strategies and the selection of the preferred option.

The project was approved by the Ausgrid Board on 24/08/2022, at a total cost of $13.8 million ($12.5 million excluding contingency).

2.6.15Ensuring reliable supply for the Sydney Airport network area

Key project milestones:

- Project initiated in June 2019.
- Project expenditure authorised by Ausgrid Chief Executive Officer in September 2020.
- Project completion is expected by January 2025.

Options Analysis

The 33kV switchgear at Sydney Airport is compound insulated with oil-filled circuit breakers, which could lead to failures ranging from single equipment failures to multiple equipment failures impacting the operation of an entire substation. Furthermore, the 33kV oil circuit breakers at Sydney Airport ZS were originally commissioned in 1955 and are now an orphan technology with very limited spare parts availability.

Replacement of the 33kV switchgear in a new switchroom has been identified as the only option available to adress reliability risks based on the outcome of a RIT-D. Condition issues identified in the switchroom buildings have led to the decision to construct a new 33kV switchroom building at the customer's cost to house the new equipment.

The refurbishment of the 33kV switchgear with new equipment in situ (i.e. 'brownfield replacement') was also considered under a staged approach. However, brownfield replacement imposes materially greater safety and schedule risk, arising from work being carried out next to energised equipment.

Ausgrid also considered other options such as the retirement of the 33kV switchgear or the construction of a new 132/11kV zone substation, but these options were not progressed since they were found technically or commercially not credible. In the case of simple retirement, the reliability of supply would be significantly reduced and future developments in Sydney Airport would be limited. In the case of the new substation, the cost would be materially higher than replacing the switchgear, without providing a commensurate increase in benefits.

The scope of this project includes the construction of a new building, installation of new equipment and retirement of the existing 33kV switchgear at Sydney Aiport ZS. Demolition of the existing building and site remediation will also occur as a result of the project. The new switchroom design will also support improved fire segregation, contributing to improved safety and reliability.

The project was approved by the Ausgrid Chief Executive Officer on 30/09/2020, at a total cost of $8.4 million ($7.5 million excluding contingency).

2.6.16Tarro ZS 11kV Switchgear Replacement

Key project milestones:

- Project initiated in September 2021.
- Project expenditure authorised by the Ausgrid CEO in April 2023.
- Project completion is expected by January 2025.

Options Analysis

Two network options were considered to resolve the above issues:

Option 1 – Replace the existing 11kV switchgear at Tarro ZS

This option involves the replacement of the 11 kV switchgear in a new switch room, as well as enabling works to add a third 11 kV switch group in future to meet future load. This option involves the replacement of the existing 11 kV double bus switchgear at Tarro ZS with modern equivalent switchgear in a single bus arrangement.

The scope of this option includes:

- installation of a Modular Equipment Room (MER) adjacent to the 33 kV switchgear;
- installation of a new 11 kV switchboard including two sections of single bus switchgear and 13x11 kV circuit breakers;
- installation of 11 kV connections to connect both existing main power transformers to the MER and transfer seven existing 11 kV feeders to the new switchboard;
- construction of firewalls between transformer bays and on the western boundary to protect a residential property;
- rearrangement of the 33 kV feeder connections and structures within the site to achieve safety clearances required for internal 11 kV cable work;
- secondary systems upgrades; and
- disconnect, dismantle and remove the existing 11 kV switchgear from the site.

The net present value (NPV) of this option was $28.6 million.

Option 2 -Build a new zone substation to replace the Tarro ZS

This option involves building a new 33/11kV zone substation next to Beresfield STS to replace the existing Tarro ZS.

The scope of this option involves:

- installing two 33/11 kV transformer units;
- installing an equivalent 11 kV switch room with the same configuration proposed under Option 1;
- installing control and protection equipment (secondary systems) to integrate the new ZS to the network;
- installing two 33 kV underground short cable connections (approximately 200 metres long);
- transferring 11 kV load from the existing Tarro ZS to the new ZS;
- transferring the large industrial customer to the 33 kV network (by installing a 10 MVA transformer unit with reclosers and 11 kV circuit breakers to connect to the customer's own substation); and
- decommissioning the existing Tarro ZS)

The NPV of this option was $18.2 million.

Option 1 provides the highest NPV and represents the most cost-effective way to address identified risks. In addition, it provides the flexibility required to address both the immediate needs of the existing network and the potential needs of future connections in a staged manner, which is a prudent approach considering that such future connections may not materialise. If prospective loads are realised, it is likely that load growth will occur over an extended period, as similar industrial estates in the area are not fully occupied after 10 years.

The project was approved by Ausgrid CEO on 6/04/2023, at a total cost of $12 million ($10.7 million excluding contingency).

2.6.17132kV Feeders 923/2 & 924/2 Mason Park STSS – Burwood ZS

Key project milestones:

- Project initiated in June 2022.
- Project expenditure authorised by the Ausgrid CEO in December 2022.
- Project completion is expected by September 2025.

Options Analysis

Two network options were considered to resolve the above issues:

Option 1 – Replacement of SCFF feeders along the existing route

This option involves the like-for-like replacement of approximately 1.6 kilometres of existing underground SCFF feeder sections with a modern equivalent (Cross Linked Polyethylene cables (XLPE)) in their existing configuration. This would require:

- works at Mason Park STSS, Strathfield TP and Burwood ZS to facilitate the new 132kV feeder connection;
- installation of two 132kV XLPE feeders of approximately 1.6km from Strathfield TP to Burwood ZS, with a proposed firm rating of 230MVA;
- metering, control and protection communication upgrades at both ends; and
- decommissioning of the existing SCFF feeder between Strathfield TP and Burwood ZS.

The NPV of this option was $43.7 million.

Option 2 - Replacement of SCFF using a different route along smaller residential streets

This option uses an alternative, optimised underground route from the Burwood ZS to the Ismay Reserve that enables the decommissioning of the Strathfield TP and removal of approximately 230 metres of dual circuit overhead lines from Paramatta Road to Strathfield TP.

The use of this route alignment results in considerable cost savings compared to Option 1, due to:

- a shorter route alignment (Option 2 is approximately 100 metres shorter than Option 1);
- the use of existing conduits installed as part of the WestConnex motorway project over part of the route; and
- construction taking place along smaller residential streets (compared to Option 1) which minimises traffic management costs and enables the construction to be completed during day-time hours.

Under this option, the Strathfield TP can be decommissioned. Additionally, the removal of overhead lines increases visual amenity and results in an associated reduction in safety risk from the potential for overhead cable strikes.

Specifically, the works for this option include:

- construction of 1.5 km of dual circuit ductline between Lloyd George Avenue, Burwood and Ismay Reserve, Strathfield;
- construction of one joint bay mid-way along the proposed route;
- installation of new XLPE cables along the dual circuit ductline;
- relocation of 11kV feeder along Concord Rd and recovery of redundant 33kV cables;

- installation of two new steel UGOH (underground to overhead) poles in the Ismay Reserve;
- removal of 230m section of dual circuit overhead wires and poles between Paramatta Rd and Strathfield TP;
- protection and communication upgrades at Burwood ZS and Mason Park STSS;
- decommissioning of the Strathfield TP at Columbia Lane, Strathfield and preparing the site for divestment; and
- decommissioning existing SCFF sections of feeders 923 and 924.

The NPV of this option was $44.7 million.

Option 2 provides the highest NPV and ensures that the Strathfield TP site can be fully decommissioned and made available for disposal. By using the alternate route, Ausgrid will be able to take advantage of conduits installed as part of the WestConnex Motorway project. In addition, removal of 230 metres of overhead lines between the Strathfield TP and Parramatta Road provides amenity improvements and reduced safety risk This option therefore causes the least impact to the community, in addition to the benefits quantified as part of the RIT-D assessment.

The project was approved by Ausgrid CEO on 23/12/2022, at a total cost of $14.7 million ($13.4 million excluding contingency).

2.6.18 Concord ZS 11kV switchgear replacement

Key project milestones:

- Project initiated in March 2019.
- Project expenditure authorised by Ausgrid Board at a meeting in August 2021.
- Project completion is expected by October 2025.

Options Analysis

The existing 11kV switchgear at Concord ZS was commissioned in 1955. Condition based tests on the switchboard have confirmed the asset condition has deteriorated to the point that the risk of failure and associated risk of customer supply interruptions has increased beyond the point where replacement is justified.

Review of the Cost Benefit Analysis (CBA) for the network and non-network options confirmed the preferred option has not changed from the Gate 2 approval (i.e. the replacement of existing switchgear with new switchgear and the build of a new switchroom). Even with the cost increase, this option retains a positive NPV and is the best of the available options.

The credible network options identified to address the asset condition issues at Concord ZS are outlined in the table below.

Option	RIT-D assessment		Gate 3 review	
	Costs ($m real)	Market NPV ($m real)	Costs ($m nominal)	Market NPV ($m real)
1. Maintain the existing 11kV switchgear (i.e. no change)	This option is not viable. Corrective action is required to address the asset condition issue.			
2. Replacement of 11kV switchgear in-situ	16.7	25.9	23.9	7.6
3. Replacement of 11kV switchgear with new switchroom	14.3	28.5	21.5	10.2

The credible network options are the replacement of the 11kV switchgear with new equipment in-situ or a new switchroom to house new equipment. The latter option had the highest market NPV in the initial analysis. The updated assessment (i.e. Gate 3 Final Project Approval) confirms that the installation of a new switchroom to house the new 11kV equipment still has the highest market NPV and therefore maintains its position as the preferred option.

Consideration was given to the establishment of a new substation to replace the existing Concord ZS, of the retirement of Concord ZS via 11kV load transfers to Olympic Park ZS. However, it was found that these options are unfeasible because their costs are significantly higher than the preferred option, without providing significant additional benefits. The new substation or the retirement via load transfers (which would have slightly reduced costs as fewer cables are required due to a reduced load forecast) are sub-optimal options in this case.

The project was approved by Ausgrid Board on 16/08/2021, at a cost of $21.5 million ($20.0 million excluding contingency).

2.6.19 Decommissioning of 132kV Feeders Lane Cove STSS – Dalley St ZS

Key project milestones:

- Project initiated in August 2020
- Project expenditure authorised by Ausgrid Board at a meeting in September 2022
- Project completion is expected by September 2024

Options Analysis

Ausgrid identified a need to address the increasing supply and environmental risks associated with 132kV fluid-filled underground feeders 928/3 and 929/1 between Lane Cove Subtransmission Switching Station (STSS) and Dalley St Zone Substation (ZS). The existing feeders utilise obsolete technology, requiring specialist skills to repair and maintain.

As a result of the implementation of the last step of the strategy in the Sydney CBD load area, Dalley St ZS is to be decommissioned. As such, the 132kV feeders supplying Dalley St ZS have become redundant. Given the condition of these 132kV feeders, there are no other viable alternatives but to retire and decommission these assets.

The project was approved by Ausgrid Board on 24/08/2022, at a cost of $3.4 million ($3.1 million excluding contingency). This approval was also provided concurrently with the decommissioning of Dalley St ZS (refer to item 2.6.12 above).

2.6.20132KV Feeder 264 Beaconsfield BSP – Kingsford ZS replacement

Key project milestones:

- Project initiated in August 2021.
- Project expenditure authorised by the Board in December 2022.
- Project completion is expected by March 2025.

Options Analysis

The 132kV underground Feeder 264, connecting Kingsford Zone Substation (ZS) with TransGrid's Beaconsfield Bulk Supply Point (BSP), is a self-contained fluid-filled (SCFF) feeder, with increasing customer supply, maintenance and environmental risks. Feeder 264 forms part of a ring network that connects Beaconsfield BSP and Bunnerong Subtransmission Switching Station via Kingsford and Maroubra zone substations. The availability of Feeder 264 is critical to supplying these zone substations.

One credible network option has been identified to address asset condition issues on feeder 264. It involves the replacement of the existing feeder like for like, using modern equivalent technology – Cross Linked Polyethylene (XLPE) cable.

The scope of this project includes:

- works at Beaconsfield BSP and Kingsford ZS to facilitate the new 132kV feeder connection;
- extending the existing dual circuit 132kV ductline between Beaconsfield BSP to O'Riordan Street, Mascot to accommodate replacement of SCFF Feeder 264 and future replacement of Feeder 9FF;
- construction of a 4.5km single circuit ductline to accommodate Feeder 264, between O'Riordan St, Mascot and Kingsford ZS;
- installation of one 132kV XLPE feeder of approximately 5.5km from Beaconsfield BSP to Kingsford ZS, with a proposed firm rating of 230MVA;
- metering, control and protection communication upgrades at both ends; and
- decommissioning of existing SCFF feeder between Beaconsfield BSP and Kingsford ZS.

The NPV of this option was $135.7 million.

Given the low deferral value available for reducing demand and the scale of load reduction required it was determined that non-network options could not form part of a credible option for this replacement investment.

The project was approved by Ausgrid Board on 7/12/2022, at a total cost of $26.5 million ($23.3 million excluding contingency).

2.6.21132kV Feeders 9SA & 92P Beaconsfield BSP to Campbell St ZS/Belmore Park ZS and Loop Zetland ZS into Feeder 92P

Key project milestones:

- Project initiated in September 2021.
- Project expenditure authorised by the Board in December 2022.
- Project completion is expected by September 2025.

Options Analysis

Three network options were considered to resolve the above issues:

Option 1 – Replace the existing feeders 9SA, 92P, 260 and 261 like-for-like using modern equivalent technology.

This option involves the replacement of 132kV Feeders 9SA, 92P, 260 and 261 by undertaking a like-for-like replacement using contemporary technology, which is expected to improve reliability, reduce EUE levels and reduce operating expenditure over time relative to the base case of maintaining the existing feeders. Under this option, the configuration of the feeders would remain unchanged from the existing network arrangement.

The NPV of this option was -$0.1 million.

Option 2 – Replace SCFF sections of feeders 9SA and 9SP, loop Zetland ZS into feeder 92P and close Zetland 132kV busbar.

This option involves the decommissioning of feeders 260 and 261, avoiding the need to replace them with updated technology. This is achieved by replacing the 132kV SCFF sections of cable in 9SA and 92P as well as a reconfiguration of feeder 92P to form feeders 92P and 9CY, each with a rating of 230MVA. Feeders 92P and 9CY would then be connected into the Zetland ZS while feeder 9SA would remain connected between the Beaconsfield BSP and the Campbell Street ZS.

The NPV of this option was $5.4 million.

Option 3 – Replace SCFF sections of feeders 9SA and 92P, loop Zetland ZS into feeder 92P and defer works on closing Zetland 132kV busbar

This option is similar to the specification of Option 2 but involves staged replacement works to replace the feeders initially, by looping Zetland ZS into feeder 92P, and the works to close the Zetland ZS 132kV busbar at a later date.

In the future another transmission path will be required between Beaconsfield and Haymarket BSPs, once SCFF feeders 90T/1 and 9S2 are retired, requiring the 132kV bus section circuit breaker at Zetland ZS to be operated normally closed. Zetland ZS will be a dual function asset, becoming a transmission node on the completion of the project.

The NPV of this option was $6.6 million.

Option 3 provides the highest NPV and represents the most cost-effective way to address identified risks to customers and the environment, noting that works at Zetland ZS can be deferred until FY34. By this time, another transmission path between Beaconsfield and Haymarket BSPs is needed upon retirement of SCFF feeders Commercial in 90T/1 and 9S2, thereby requiring the 132kV bus section circuit breaker at Zetland ZS to be operated normally closed.

The project was approved by Ausgrid Board on 7/12/2022, at a total cost of $29.3 million ($25.9 million excluding contingency).

2.7 Urgent and unforeseen investments

There were no distribution network projects required to address an urgent or unforeseen network investment in the preceding year.

Similarly, there were no dual function network projects required to address an urgent or unforeseen network investment in the preceding year.

3. Non-network Opportunities

3.1 Demand Management

When Ausgrid identifies a network limitation, SAPS and non-network options are considered as an alternative to the preferred network option.

A SAPS alternative means providing customers affected by the identified network limitation an alternative supply source to the electricity grid. A typical SAPS would comprise a renewable energy supply source such as solar, battery storage and a backup generator such as a diesel generator.

The implementation of a non-network alternative is commonly referred to as demand management in that the solution has historically involved the reduction or modification of customer demand for grid supplied electricity. But with rapidly developing alternatives such as advanced solar and battery inverter control, demand management solutions can now include support for voltage unbalance, power factor and harmonics management.

Demand management is an important part of efficient and sustainable network operations; and can help address a network need due to rising customer demand, aging network assets, voltage unbalance or other investment driver. Effective use of demand management reduces the cost to maintain the network and results in lower electricity bills for all customers.

There are a range of demand management or non-network solutions available for use by electricity networks. Examples include:

- Energy efficiency (e.g. replacing lights with more efficient, lower wattage options).
- Demand response (e.g. operating appliances at lower power demand for short periods such as air conditioner load control).
- Operation of embedded generators (including renewable generators).
- Energy storage (e.g. batteries).
- Power factor correction (a form of energy efficiency).
- Load shifting (shifting equipment use from peak to non-peak periods such as off-peak hot water).
- Converting the appliance energy source from electricity to an alternative (e.g. switching from electric to gas heating).
- Voltage management (e.g. operation of customer inverters in voltage support modes).

When a review of a network limitation is initiated, a review of options that includes both network and non-network options is completed. The goal is to identify the solution which offers the highest net benefit and meets the required reliability standards. The solution may be:

- Modifications or additions to the existing network (i.e. network solution).
- Support of the existing network by others (i.e. non-network or demand management solution).
- Blended solutions incorporating network modification or additions and non-network demand management elements (including, though not limited to SAPS and microgrids).

Ausgrid's planning process assesses network needs across different network areas. Solution options are developed by area for all known network needs to allow for comprehensive solutions to address multiple needs.

To ensure a thorough investigation, Ausgrid consults with the community on larger projects about the network requirements and the potential non-network options available.

To determine the right balance, we apply the process depicted in Figure 3.1 following. For projects where the preferred network option cost is greater than $6 million, the Regulatory Investment Test for Distribution (RIT-D) process is followed. The orange boxes denote the reports which are published as part of the RIT-D process.

For projects where the preferred network option cost is less than $6 million, Ausgrid applies a similar but simplified process appropriate to the cost of the project.

The RIT-D process is a cost-benefit test that must be applied to all network investment projects where the most expensive credible option costs more than $6 million. It must be applied by network distribution businesses when assessing the economic efficiency of different investment options to select the option with the highest market benefit that address the network needs.

This helps to promote better consistency, transparency and predictability in our planning processes and follows the NER rules under Chapter 5.

The AER published an update to the RIT-T and RIT-D application guidelines in August 2022 which stipulated that distribution network service providers (DNSPs) can connect customers to a SAPS where it may be cheaper, safer and more reliable than connection to the grid. These will become regulated SAPS.

Customers connected to regulated SAPS will receive an equivalent level of customer protections and will pay for their electricity in the same way as grid customers. Both SAPS and grid customers can benefit from lower charges and improved system reliability.

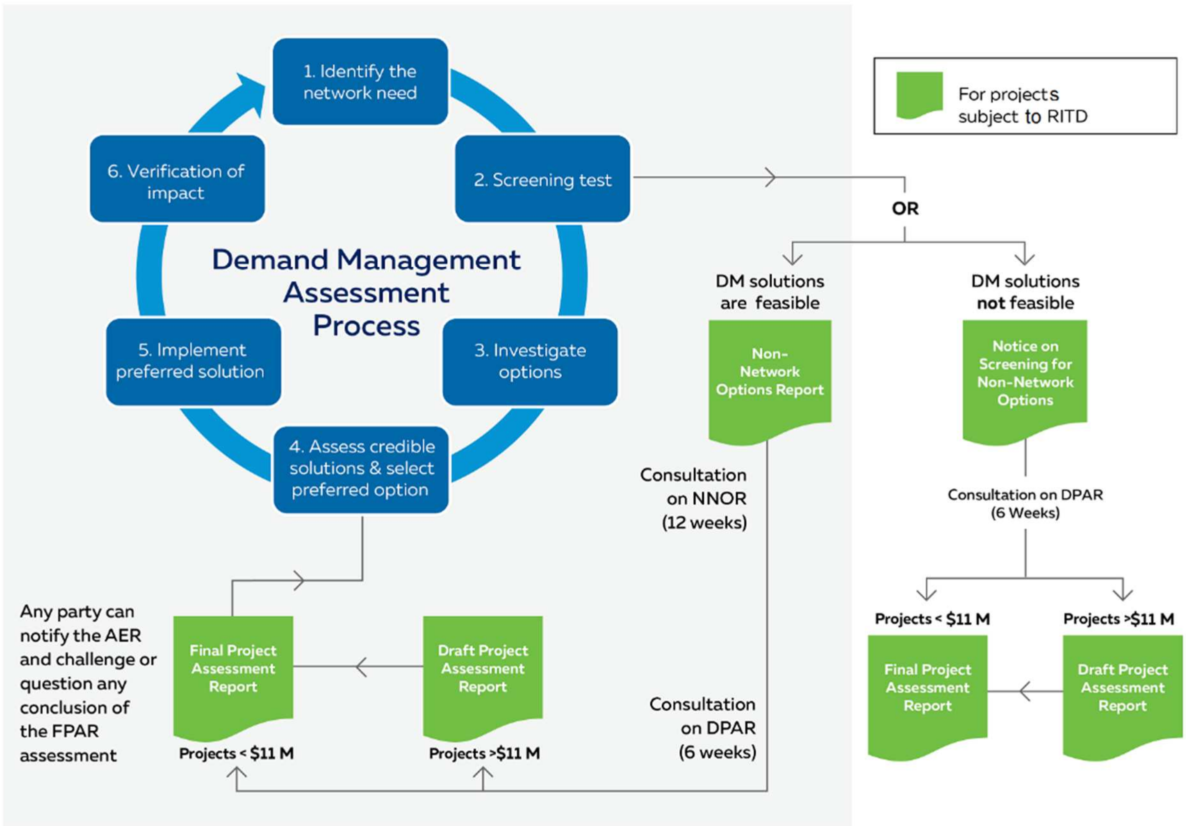


Figure 3-1: Demand Management Assessment Process

3.2 Demand management considerations

3.2.1 Demand management considerations in 2023

There were 14 projects in the forward planning period which met Ausgrid's criteria for SAPS and demand management consideration. Ausgrid assesses the viability of demand management alternatives for projects which are scheduled for the forward planning period and which meet minimum threshold costs.

Assessment for non-network solutions has determined that no major projects were identified where it was considered likely that SAPS or demand management would form part of the least cost solution to the need. It should be noted that the level of analysis is of a high level nature and that the assessments for all projects were based upon preliminary assumptions for project costs, unserved energy and other benefits.

A full assessment conducted as part of the RIT-D process, including a request for submissions via the Non-Network Options Report or equivalent, will occur in future for each respective project at the relevant time. Refer to Section 2 of this report for the forward schedule for our RIT-D projects.

3.2.2 Demand management in the forward planning period

As noted above, for the forward planning period, a preliminary demand management assessment has determined that non-network alternatives are unlikely to offer a cost-effective option for our major projects scheduled for implementation prior to 2030.

While there are no major network investment projects in the forward planning period where SAPS or demand management solutions are likely to be feasible, there are three areas of localised high growth where demand management solutions may form part of a least cost solution to the needs. Load growth in these areas is being driven by growth in residential demand on hot summer days.

If growth continues, a possible need may arise at which point a planning investigation including assessment for demand management potential solutions will be undertaken.

While these network needs are unlikely to trigger a RIT-D process (due to the likely costs for any preferred network option) , we apply a similar but simplified process appropriate to the cost of the project. Where public consultation forms part of the assessment, non-network option reports will also be published on Ausgrid's website. Those on Ausgrid's Register of Interested Parties will be notified of the publication of any opportunity. You can register your contact details at www.ausgrid.com.au/dm.

3.3 Demand management activities in 2022-23

3.3.1 Demand management projects initiated in 2022-23

There were no demand management projects initiated in FY2022-23 that were linked to a network investment need.

3.3.2 Demand management projects implemented in 2022-23

There were no demand management projects implemented in FY2022-23 that were linked to a network investment need.

3.3.3 Demand management innovation

As part of our efforts to explore alternative demand management solutions, Ausgrid investigates potential demand management solutions that may offer cost-effective alternatives to traditional network options. These research and development projects are funded through the Demand Management Innovation Allowance (DMIA) and approved by the Australian Energy Regulator.

Ausgrid's demand management innovation program is part of our strategic innovation program which aims to explore solutions relating to the risk associated with the retirement/replacement of aged assets (85% of Ausgrid's capital program), emerging technologies such as battery storage and electric vehicles, customer-side alternatives to improving solar hosting capacity, hot water load control and to explore solutions enabled by smart meters and Internet of Things (IoT) automation.

Ausgrid strongly encourages interested parties to engage with us on new and innovative project ideas or proposals that aid the transition to our net zero future. To discuss further please email us at demandmanagement@ausgrid.com.au.

During 2023, Ausgrid progressed ten DMIA projects. A description of the projects is provided in the following table.

Table 3-1: Demand management innovation projects

	Project Name	Project Description
1	Hot Water Load Control	This project was developed to understand the current and future capability of hot water load control as a DM solution appropriate for the Ausgrid network and to explore how Ausgrid, retailers and customers can collaborate to optimise the operation of the hot water load control system for the benefit of all consumers. This understanding will be built through internal analysis, collaboration with customers and industry and load control field trials. Where necessary, the trials will include partnerships with third parties including metering providers and energy retailers. The project was planned to take place over two to three years from 2021 to 2024 as follows: <u>Phase 1 - Scoping study (data analysis, technology, and market assessments)</u> The first phase of the project included preparations needed to develop a detailed scope for further phases of the project. The first phase activities included: • Analysis of hot water load control and solar customer information to determine suitable trial locations. • Technology assessment of smart meter control functionality in the market. • Market assessment of metering provider and retailer commercial models and arrangements • Customer research to better understand customer perceptions, understanding and responses to appliance load control and controlled load tariffs in general. <u>Phase 2 – Trials</u> A total of 638 residential customers with smart meters were selected to be part of the trial, of which 233 had solar PV. The 638 residential customers came from different parts of Ausgrid's network, covering Sydney, the Central Coast, and the Hunter region. Ausgrid engaged a metering provider to remotely modify the turn-on and turn-off of the controlled load circuit for trial customers. The smart meter functionality allowed programmable switching times differentiated by season and day of the week. Within each day under the trial, there were two separate periods when the scheduling was active. The key parameter being tested during 2021-22 was the effectiveness of including an additional daytime scheduling window to the existing OP1 controlled-load tariff or "solar soak" in shifting overnight energy usage into the daytime. Note that the amount of energy able to be shifted is subject to variability based on each customer's hot water service pattern of use; primarily the hours of the day hot water is being used balanced against the characteristics of their hot water system such as tank capacity, state of degradation and quality of insulation. Based on analysis of the average load profile, around 30-50% of the overnight energy consumption under the OP1 tariff was successfully shifted into the daytime during the trial period from October 2021 to March 2022. Furthermore, for those customers with solar PV systems, up to 50% of solar energy exports were shown to be offset by the solar soak arrangement over the same period.

	Project Name	Project Description
		In terms of quantifying a possible financial benefit, the estimated market benefit of shifting half of the OP1 energy into the daytime was valued at around $23 per OP1 customer per year based on the average wholesale market energy price of $58/MWh in October 2021. The financial benefit will vary according to fluctuations in market conditions. The rate of hot water related complaints from customers during the trial was only 0.3% (2 out of 638), which is low in comparison with the 1.1% call-out rate for hot water related complaints across the Ausgrid network. This meant that during the trial, the OP1 schedule changes had little to no noticeable impact on customers' hot water service. The trial results demonstrate and confirm the success of the schedule changes. The next step was to expand the trials to additional Ausgrid network areas and include additional retailers and metering providers. This may include surveying customers to explore customer understanding and preferences around controlled load tariffs. <u>Phase 3 – Market enablement</u> The following activities took place during 2022-23: • Ausgrid's ES7 Network Price Guide was updated to include new controlled load switching times, enabling Retailers to implement the solar-soak option for their OP1 customers. • Working with retailers to explore the implementation of the new solar-soak option. Initial testing of the solar-soak option has taken place with a sample of customers with two Retailers. • As the solar soak option enables a second operation window during the day and higher tank temperature for more hours per day, we developed a model to estimate the impact of this second window on heat losses and customers' electricity bills. The result was an estimated3-5% increase in the annual hot water electricity bill due to increased heat losses from the higher average tank temperature. • As part of the ongoing engagement and collaboration activities with relevant stakeholders, electricity retailers presented an inquiry regarding the possibility of reducing the current three-hour randomisation window of OP1 customers in Ausgrid's ES7 Network Price Guide. Ausgrid carried out modelling to study the impact of reducing the randomisation window to one and two hours. Results showed a 37% and 17% growth in peak demand (hot water circuit only) when reducing randomisation to one hour and two hours, respectively. • To complement the analysis, we estimated the impact of shifting OP1 customers from traditional overnight off-peak operation to the solar-soak operation to estimate the potential for OP1 load to absorb the energy exported by PV systems into the network. The findings indicate that, on average, solar soaking has the capacity to consume 35% of solar exports. This value fluctuates throughout the year being highest in winter months at around 50%, and around 40% during shoulder periods with the lowest potential during summer when hot water usage is typically low. • In 2022-2023, Ausgrid joined the SolarShift project (part of RACE for 2030)[1] as an industry partner. This 2-year research initiative, led by UNSW in partnership with Endeavour Energy, Solar Analytics, NSW Office of Energy and Climate Change (OECC), and Energy Smart Water (ESW), will explore coordinated control and operation of domestic electric water heating systems (DEWH) for soaking up excess solar generation. This project seeks to better understand the potential of load control as a demand management solution and develop strategies on how networks, retailers, market participants and customers can work together to optimise the operation of the controlled load system for the benefit of all stakeholders. • Preliminary scoping work has been carried out to identify key priorities for future research to understand the impacts of different hot water technologies. This research would include the customer costs and benefits of different hot water system options and their effectiveness as a flexible load. This research is expected to be launched in early 2024. As part of efforts to maximise load shifting opportunities relating to off peak hot water, a review of the regulatory framework for metering services recommended that the deployment of smart meters be accelerated to target 100% by 2030. The consultation can be found on the AEMC's website at https://www.aemc.gov.au/market-reviews-advice/review-regulatory-framework-metering-services

[1] https://racefor2030.com.au/project/solarshift-turning-electric-water-heaters-into-megawatt-batteries/

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2	Peak Time Rebate (Retailer Demand Response)	Ausgrid was seeking to assess the effectiveness of a peak time rebate (PTR) offer in localised areas of the Ausgrid network area on peak demand days. As part of the PTR trial, customers were invited to voluntarily reduce their energy usage for 2-3 hours during times of peak demand on the network, with the customers rewarded with energy credits based on their energy reduction. The project aimed to test whether this option could be used to alleviate location specific short-term network constraints, to defer or reduce the need for longer term network infrastructure upgrades through building retail partnerships and conducting trials. As such the objectives are to gain an understanding of: • Scale and density of peak demand reduction offered by PTR under various modelled scenarios for constrained network assets. • Various customer acquisition strategies and the resulting measure of localised PTR customer take-up. • Effectiveness of various customer incentives. • Customer experience. • Reliability and availability of retailer PTR platforms. The PTR project took place across 2 phases, with the first phase having commenced in 2020-21. Phase 1 included the implementation of collaborative PTR trials with retailers AGL and EnergyAustralia who introduced this solution recently for small customers. These initial trials confirmed the functionality of the retailer PTR platforms and provided insight into targeted Retailer customer recruitment strategies and customer behaviour. Phase 1 included 24 suburbs in the Lower Hunter, Newcastle West and Northwest Sydney areas of Ausgrid's service area. These areas were selected as they are representative of the local areas where high growth is expected to result in future network needs. In Phase 2, Ausgrid expanded the trial to 44 suburbs, tested automatic demand response and asked one of our partners to recruit more customers in target suburbs. This project concluded at the end of August 2023. Key outcomes were as follows: • The participation rate for opt-in recruitment averaged 53% while opt-out recruitment averaged 97%. The participation rates were relatively consistent throughout the trial, especially for events in the same season. • While opt-out recruitment led to higher participation rates, it didn't result in higher energy reductions. Almost half of opt-out participants received zero credit, which indicates that a significant portion of them were non-active participants. • On average, approximately 51% of the participants recruited via opt-out method achieved a minimum of 5% reduction, averaging around 0.98kW reduction based on the retailer's baseline. • On average, opt-in participants achieved a demand reduction of approximately 0.88kW based on the retailer's baseline. • An email recruitment campaign to register new customers resulted in an opt-in rate of 7%, which was higher than other demand management recruitment trials. An offer of a sign-up bonus resulted in an additional 2% of customers opting into the demand response program. • During the summer when a Sensibo automated air-conditioner controller was offered to customers, the device for 45% of customers was either never connected or previously connected but disconnected at the time of the event. This suggests greater engagement with customers is required to set up and use the device. There were only limited cases where the Sensibo air-conditioner controller operated the air conditioner as in most cases the air-conditioner was manually switched off or the device was not connected. • As of June 2023, approximately 55% of the customers in the trial suburbs did not have a smart meter which indicates that there is the potential to significantly increase the demand response participation rate with a higher uptake in smart meters. • Most of the participants who earned credits from the events received credits of between $1 to $10 per event. • According to an end of trial survey, approximately 85% of the survey respondents are somewhat or extremely likely to participate in future PTR events. Future considerations • Continue partnerships with our retail partners to share knowledge and identify potential uses of PTR to help alleviate network constraints. • Investigate and address challenges related to scheduling weekend and public holiday events to ensure PTR events can be scheduled on any day, not just on weekdays.

	Project Name	Project Description
		• With 22% of survey respondents not receiving a reward after taking actions to reduce their energy consumption, further investigation is required to understand baseline methodology and ways to assist customers to achieve reductions. • Explore the potential of additional notifications, such as 24-hour advance notice, to increase customer participation and performance. For further details about this trial project, an interim report of our Year 1 findings has been published on Ausgrid's Demand Management web page for Innovation Research and Trials at www.ausgrid.com.au/dm.
3	Electric Vehicle Demand Research	This project will explore the potential impacts of electric vehicle (EV) charging on the Ausgrid network by supporting ARENA-funded projects and additional activities to investigate and build capacity around demand management options for managing the charging of electric vehicles. Opportunities exist to manage this demand to reduce electrical infrastructure investments and to potentially use the stored electrical energy to provide network support services. The primary objectives of the project are: • Understand and research options for demand management interventions using EV chargers to shift or curtail demand during peak demand periods; and • Conduct or participate in practical, customer-based electric vehicle charging trials that explore the potential demand management solutions from partnering with customers, retailers and other EV industry participants. Other secondary objectives include: • Sourcing, creating, and collecting activity-based customer EV data; and • Reviewing and making recommendations on the collection of data on new demand on the network resulting from EV charging. The project will be conducted in two phases: Phase 1 - Charge Together Project support (ARENA-funded) There were three primary activity streams for this phase of the project that was initiated in 2018-2019 and were completed in 2021. Ausgrid supported all activities via in-kind support but principally supported the delivery of an EV owner survey and better understanding of customer preferences and behaviours. The three main activities were: 1. A suite of fleet products which could be provided to fleet managers with all the tools necessary to migrate their fleets to electric vehicles. 2. A product that would provide individual EV buyers with the tools necessary to make an EV purchasing decision. 3. An electricity network planning tool to assist Australian electricity network providers in planning and preparing for the impacts of EV charging on their network. Phase 2 – EV charging trials, network tariffs and industry engagement This phase of the project involved the following key activities: • Partnering with electricity retailers and other electric vehicle industry parties in the development and implementation of collaborative EV customer trials which explore a range of customer, network, electricity retailer and EV industry issues. • Engaging an economic consultant to examine the principles of network pricing and develop a network pricing framework that can be used for exploring innovative network tariffs for electric vehicle owners and electric vehicle charging network providers. Summary of project activity to date Phase 1 activities were mostly completed during 2019-2020 with the publishing of the final results of the NSW EV owners survey happening during 2020-2021. During 2020-2021, the following Phase 2 activities also commenced or were completed: • Participation as a project partner in the ARENA-funded electric vehicle charging trial led by Origin Energy. Further information can be found under 'Projects' on ARENA's website.

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		• Participation in the technical reference group along with other network companies in the ARENA-funded electric vehicle charging trial being led by AGL. Further information can be found under 'Projects' on ARENA's website[2]. • Completion of the electric vehicle network pricing consultancy by HoustonKemp outlining recommendations for electric vehicle tariffs. During 2021-2022, the following Phase 2 activities were conducted: • Enhancements made to the EV charging planning tool, informed by the comprehensive customer survey. One of the key outcomes from this component of the project was a greater understanding of how the electrification of the transport sector will create new electricity demand in different locations of the network with materially different characteristics. • Analysis of EV charging data up to May 2022 collected from Origin EV Smart Charing trial. Through 2021-22 the trial successfully installed more than 150 smart charging EV chargers, which were used to test different scenarios of unmanaged, incentivised, and managed charging models with Origin customers. Communication of the lessons learnt from AGL EV trial with other stakeholders. Ausgrid is one of seven network companies on a technical reference group to the AGL EV Orchestration Trial and AGL has published two new Lessons Learnt Reports up to March 2022 where AGL had signed up 400 participants with 200 smart chargers installed. Key learnings based on the 12 Ausgrid residential participants of the Origin EV Smart Charging trial, Mar-21 to Mar-22 (full dataset was not able to be obtained prior to completion of the trial): • On an average day, EV owners do not necessarily plug in their EVs and vehicles are not necessarily being charged while plugged in. • During Unmanaged charging, around 30%/24% of EV charging occurred during peak time on a weekday/weekend. Weekday charging is higher during both peak and overnight periods compared to weekends owing to greater distances travelled on weekdays impacting on greater charging requirements. Conversely, solar soak charging is higher on a weekend likely due to more EVs being garaged at home on weekends. • In Experiment 1, with the introduction of the simulated time-of-use incentive, the percentage of peak time charging drops significantly compared to Unmanaged, reduced to 10% on a weekday. Overnight charging increases from 38% to 55% and solar soak charging increases from 25% to 31%. • In Experiment 2, as chargers are curtailed to 0kW during peak time (with an opt-out option but forfeit the reward) peak time charging is reduced further to 8%/4% on a weekday/weekend. The majority of EV charging is shifted to overnight. However, an artificial spike in demand was observed immediately after the peak period, indicating the need to better manage the scheduled turn-on of EV charging. • Experiments 1 and 2 demonstrated the efficacy of time-of-use pricing signals in changing EV charging behaviour compared to the baseline Unmanaged charging scenario. Controlled charging, such as the peak exclusion period under Experiment 2 demonstrate the need to manage the turn-on behaviour of EV charging, due to the impact of numerous chargers turning on at once following an exclusion period. • Ausgrid then translated the trial outcomes to example LV distributors under a simulated setting with 50% EV penetration, it was found that while peak demand can be managed effectively, care should exercised when applying the solar soak incentive period to LV distributors that experience high demand near the middle of the day. During 2022-2023, the following Phase 2 activities were concluded: • Analysis of EV charging data and finalisation of the Origin EV Smart Charging Trial and ARENA report • Exploration of the opportunities and challenges of fleet electrification and grid integration, in partnership with industry and research institutions. • Exploration of the current state of V2G technology, precedent research, standards and development of a pathway for connection to enable future trials using V2X technology. • Participation in the ARENA V2X Opportunities and Challenges report through supporting a DNSP reference group to understand the current state and opportunity for customer adoption of V2X technologies in Australia to inform future project trials. Results from 2022-23:

[2] https://arena.gov.au/projects/agl-electric-vehicle-orchestration-trial/

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		During 2022-23, Ausgrid supported project partners with input towards a knowledge sharing and closure report[3], which was published by ARENA in August 2023. Further information from Origin's preceding learning reports can be found on the ARENA website. Ausgrid's role provided input into trial design to shape how the trial explores different elements of EV charging behaviour, informing Ausgrid's understanding of the EV demand impact on the distribution network and how unmanaged and managed charging techniques impact local network assets. Detailed analysis of results from the Origin smart charging trial was published in Ausgrid's DMIA report for 2021-22 available on the AER website. In 2022-2023 Ausgrid sought to build understanding of the current state of V2X bi-directional charging technology in Australia, which supported the development of a connection pathway in advance of CEC product listing for eligible bi-directional chargers that were AS4777.2 compliant, within a controlled setting on the network. • ARENA has published a new report on the Opportunities and Challenges for Bidirectional Charging in Australia[4]. The study led by enX Consulting provides an overview of the current state of V2X technologies and the associated opportunities and challenges for the Australian market. • Ausgrid supported the project through participation in the DNSP reference group with representation from 9 distribution network businesses aimed at sharing knowledge and experience of integrating V2X technologies and trials. • International insights also indicate how network distribution business collaborations are helping to spearheaded standards development and product testing processes to accelerate V2G technology and market readiness. • In addition to the value EVs already provide through lower running costs and reduced vehicle emissions, V2X services can support the energy transition through allowing EV owners to unlock further value from their vehicle battery to power a home, business, appliances or export into the wider electricity grid at times of high demand. • Ausgrid supports further industry collaboration and customer research to advance this nascent industry and further support customers to electrify, decarbonise and unlock value from their consumer energy resources, through identifying effective demand management solutions from new flexible technologies. • Ausgrid is collaborating with a local council which has Australian Standard certified Quasar Wallbox chargers. This is supporting Ausgrid to develop a process to review, commission and test bidirectional technology for safely enabling certified bi-directional electric vehicle chargers on the network. This provides Australian Standard certified V2G equipment a pathway to connect to Ausgrid's network. • As the ARENA report indicates, the industry is shifting to CSS-based V2G and Ausgrid will continue to support future innovation and trials as CCS-based field trials become possible in Australia, to inform industry's understanding and implications for power system planning. This EV demand research project has been critical foundation research on preparing for the update of significant new loads from electrification of transport. Ausgrid will continue to focus on new innovation and demand management solutions to support efficient and effective EV integration through further research and innovation projects. The below outlines how these findings will be taken forward: • **EV visibility:** Ausgrid continues to build capability for visibility of EV charging across the network and analysis of load profiles as EV uptake scales will continue to support Ausgrid's demand forecasting. • **Network Tariffs:** Ausgrid continues to trial new technology agnostic tariffs that could complement retail EV products well including the Super Off-Peak tariff and Flexible Load tariffs. Details of these can be found in Ausgrid's Tariff trial notification[5]. • **Customer Research:** Ausgrid has since explored further industry collaboration opportunities to undertake further research targeting larger trial sample sizes as adoption of EVs and diversity of customer preferences and priorities increase over-time.

[3] Origin EV smart Charging trial: https://arena.gov.au/projects/origin-energy-electric-vehicles-smart-charging-trial/

[4]https://arena.gov.au/knowledge-bank/v2x-au-summary-report-opportunities-and-challenges-for-bidirectional-charger-in-australia/

[5] Trial Tariff notification 2023-24 https://www.aer.gov.au/system/files/Ausgrid%20-%20Tariff%20trial%20notification%20-%202023-24.pdf

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		• **Commercial Fleets:** Ausgrid is partnering with industry and research institutions to explore commercial fleet electrification, which presents a unique set of opportunities and challenges for load flexibility and demand management solutions across different fleet sectors. • **Bi-directional charging:** Ausgrid continues to explore opportunities to trial and demonstrate flexible services provided by bi-directional chargers as new eligible technology enters the Australian market. • **Charging infrastructure:** Ausgrid is working with industry partners to increase the availability of on-street parking and public EV charging infrastructure. This project concluded in June 2023. Preliminary findings and reports are published on Ausgrid's Demand Management web page for Innovation Research and Trials at www.ausgrid.com.au/dm.
4	Digital Energy Futures	This project was a 3-year research project led by Monash University in which Ausgrid was a co-funding and in-kind contributor in partnership with Energy Consumers Australia and Ausnet Services. The project had been granted funding from the Australian Research Council (ARC) due to its innovative combination of research techniques. The project aimed to understand and forecast changing digital lifestyle trends and their impact on future household electricity demand, including at peak times. The project expected to generate new knowledge by employing digital ethnography and sociological theories to investigate how changing social practices will impact on electricity sector planning. This should provide significant benefits, such as lowering the cost of infrastructure spending, and helping secure affordable electricity provision. The project has 5 key objectives, which are to: 1. Understand how Australian household practices (e.g. heating, cooling, entertaining) are changing and likely to change in relation to emerging digital technologies and across different electricity consumer groups. 2. Identify emerging future scenarios and principles that will affect electricity sector planning in the near-medium (2025-30) and medium-far (2030-50) futures. 3. Develop a theoretical and methodological approach to anticipate changing trends in household practices and energy demand, which brings a futures perspective to theories of social practice and digital ethnography. 4. Develop an industry-relevant forecasting methodology for tracking and anticipating peak electricity demand, and energy consumption more broadly, that incorporates insights from this future-oriented social science research. 5. Develop practical demand management solutions for Australian electricity network businesses to plan for efficient, cost-effective and reliable networks. The project took place over 3 years, starting in late 2018-19 and continuing through to at least 2022. There were 6 stages to the project that were put forward in the ARC grant proposal: **Stage 1:** Digital and energy futures analysis – to inform the ethnographic research and establish trends (Year 1, objective 1); completed in 2020-21 **Stage 2:** Digital ethnography with households – with consumer groups in Ausgrid's and AusNet's work areas to generate future scenarios and medium-far futures principles (Years 1 and 2, objectives 1, 2 and 3); completed in 2020-21. **Stage 3:** Survey supplement for ECA's annual Energy Consumer Sentiments Survey – (Years 2 and 3) objectives 1, 2 and 3; completed in 2020-21. **Stage 4:** Scenario innovation workshops – with residential consumers in Ausgrid's and Ausnet's networks to update and extend the scenarios and principles (Year 2, objectives 1, 2 and 3); in progress and to be completed in 2022-23. **Stage 5:** Modelling and forecasting development – to cross-analyse, translate and refine the findings, and develop a forecasting methodology (Year 3, objectives 3 and 4); in progress and to be completed in 2022-23. **Stage 6:** Demand management innovation – to identify opportunities in emerging trends that are likely to impact the affordability and reliability of electricity supply for residential customers (Year 3, objective 5); completed in 2021-22 . The changes to the Energy Consumers Australia Sentiment survey were completed during 2020-2021 and the results were published in June 2022. Ausgrid was involved in providing input, review and feedback to the research team and project partners in the development of the new content and questions. The Stage 2 qualitative research was delayed due to the impacts of the COVID-19 pandemic in 2020 and the research techniques used were adapted to go online rather than face to face. All virtual

	Project Name	Project Description

		interviews were conducted successfully during the 2020-2021 period. A report entitled *Digital Energy Futures: Future Home Life* was published in July 2021 and can be found on Monash's website.
		
		One of the key results so far, was that the customer research does not strongly support the industry visions and predictions in many cases. This will need further consideration by the energy industry in terms of how to best design demand management solutions and engage with customers to increase participation in programs that aim to manage electricity demand. Of note, was that the industry visions of smart appliances and energy management systems enabling automation and more efficient management of energy and reduced peak demand was not well supported by the customer research. Consumers appeared to have limited interest in technology for energy management and many participants expressed preferences for manual control over automation when it came to appliances like heating/ cooling systems. The main appeal of digital technologies to consumers was about increasing pleasure and entertainment in the home rather than opportunities for energy management.
		
		Results from the Stage 6 Demand Management Innovation were published in December 2021 entitled *Digital Energy Futures: Demand Management Opportunities* available on Monash's website. The focus of this report was to build upon the *Future Home Life* research and focus on enabling household demand flexibility to respond to grid constraints and shifts in electricity supply.
		
		In the regulatory year 2022-2023 the following activities concluded this project:
		
		• The research findings from preceding stages informed the development of plausible Future Living Scenarios to illustrate how people may live in the future. This was explored through different customer profiles in relation to emerging energy technologies and leads to system planning and demand management considerations for the future, including how customers might interact and participate with demand management initiatives and seeking equitable outcomes as the transition leads to new customer inequities.
		• The final report was published in February 2023[6] and recommends that industry prepares for more diverse forms of customer participation and engagement as people don't only use automation for energy purposes, often override CER to maintain control, and match CER use to their everyday priorities & values.
		• The four scenarios reflect plausible futures based on the Digital Energy Futures project evidence base, including qualitative research over the 4-year study period in Victoria and New South Wales 70 households and was supported by national data and trends from the Energy Consumer Behaviour Survey.
		• The scenarios also draw on demographic, technology, economic and environmental trends:
		    o Creature comforts – envisions a 2030 world of rising living costs and household investments in consumer electronics and home upgrades.
		    o Hunkering down – builds on the creature comforts scenario, taking the trend further to 2050 where homes are optimised for safe, productive and comfortable refuge from extreme weather and climate change.
		    o Sharing the load – envisions a 2030 world where households invest where possible in solar panels, storage and electric vehicles. Households share their investments with the wider network, through exports in addition and smart technology helps manage home usage and demand management.
		    o Sunrises and siestas – envisions a 2050 scenario where institutions and society must adapt to the risks associated with climate change through policy, community initiatives and infrastructure.
		• As part of the launch of the Final Report, Ausgrid supported the presentation of the Digital Energy Future's work at the Energy Consumers Australia foresighting forum in February 2023, including an innovative interactive showcase of the research findings, scenarios and industry engagement.
		
		The DEF evidence showed that:
		
		• People don't only use automation for energy purposes;
		• People can override CER to maintain control;
		• People often match CER use to their everyday priorities and values; and
		• There are significant inequities in access, and knowledge, to operate CER.

[6] Reports published at https://www.ausgrid.com.au/Industry/Our-Research/DMIA-Research-and-trials/Digital-Energy-Futures and https://www.monash.edu/digital-energy-futures/home

	Project Name	Project Description
		The DEF scenarios reveal that industry needs to consider, encourage, and prepare for more diverse forms of participation and engagement than CER uptake to maintain high levels of material certainty. For Ausgrid, this will be explored through future initiatives informed by this study, including: • Explore the implications and importance of social research in guiding future programs. DEF findings provide a key foundation to inform how Ausgrid considers customer behaviours and social science to examine implications on the effectiveness or potential barriers to enabling a customer response to dynamic pricing and demand management. • Future research should consider how diverse social priorities guide customer response to retail products and services that are expected to emerge as market participation opportunities increase through dynamic pricing and demand management opportunities, in addition to how implementation approaches consider equity and efficiency to unlock customer benefits and participation. • Identify opportunities to further explore customer preferences including quantitative, qualitative and longitudinal research to expand on the future living scenarios and improve Ausgrid's understanding of the materiality of the future living scenarios in system planning and future demand management projects. • Work with range of stakeholders (customer advocates, academia, industry) to identify and deliver collaborative research to explore new demand management opportunities raised through the Digital Energy Futures project, including the implications on automated futures through smart technology and mobility. • Consider the design of customer facing trials and programs include appropriate customer quantitative and qualitative research components. • Consider how new vulnerabilities and equity issues will occur through the energy transition and ensure inclusive design of projects is considered in future demand management and innovation trials and research. This project concluded in June 2023. More information about the Digital Energy Futures project and links to the reports can be found on Ausgrid's website at: https://www.ausgrid.com.au/Industry/Our-Research/DMIA-Research-and-trials/Digital-Energy-Futures
5	Community Battery Feasibility Study and Research	This project aimed to develop a feasibility study and model business case for community batteries as a solution for local network constraints. The program was designed to research and develop capability in a new and innovative approach to managing network constraints driven by peak load, minimum demand and associated issues with voltage, system frequencies and power quality management, and the need to manage diverse power flows and system security issues. The project was planned to take place over three phases: **Phase 1** – Feasibility study and model business case The first phase of the project was to develop a Feasibility Study and Model Business Case for community batteries as a solution for local network constraints. **Phase 2** – Customer Research – quantitative survey and qualitative online forum. The second phase of the project included a quantitative survey of Ausgrid customers to assess the customer response to the concept of a community battery and to better understand customers' perceptions and motivations to participate in a potential trial of the concept. **Phase 3** – Community Battery Trial. The outcomes of the feasibility study and customer research will inform a practical trial of the concept. A detailed analysis of the customer research was completed and finalised in November 2020. Some of the key findings in the report specifically relating to community batteries included: • Unprompted awareness of any home battery alternative is low, with only 16% of those surveyed stated they were aware of options for customers with solar power to store the energy they generate other than having an individual battery system installed at home. • Those surveyed were more likely to be aware of the term 'community battery' than the concept, with awareness higher among those with larger PV systems and single batteries and early adopters. • Following a basic description of Ausgrid's community battery concept, there was a very high level of interest with just over half (53%) rating their interest level at 9 or 10 out of 10. • Further, nearly half said they were 'highly likely' to sign up to a community battery if the opportunity arose in their area and it was affordable. • Customers were asked about their level of comfort with different organisations providing a community battery service, with 67% of customers rating electricity networks at 8 to 10 out of 10. 43% and 40% of customers rated local councils and energy retailers respectively at this comfort level.

	Project Name	Project Description
		• Customers' expectations of the main benefits they would receive from a community battery solution, were around being to save more money, acquiring additional storage, lower set up costs, environmental costs and sharing/economies of scale.71% of non-solar customers surveyed who were considering installing solar within the next 2 years, were either much more or somewhat more likely to take up solar if they had the opportunity to be connected to a community battery. As a part of the Phase 3 for the community battery trial program, quarterly surveys were conducted with the existing participants. The first survey was conducted in January 2022 and the second survey was conducted in April 2022. More than 25 trial participants completed the survey sharing their feedback with the team. The questions in the survey revolved around the customer experience of being a part of this innovative trial. Some of the key findings from the customer surveys are shared below: • Most customers would promote the project. When asked if they would promote the community battery trial, more than 50% were excited to be part of the trial and would promote the trial amongst their family and friends. • Most customers had a positive experience. When asked about their experience in getting started in the trial, which included the sign-up process, installation of a hardware measurement device and getting started on their online app, only 1 out of the 28 customers who participated in the trial rated their experience as being "poor" with the remaining respondents saying their experience was either "good" or "very good". • Customer level of understanding was high. The survey found that 23 out of 28 customers were confident that they had the required information and understood the benefits of participating in the community battery trial. • Most customers found the app useful. Participating customers' energy use data was accessible via the app and via an online portal. About 70% of customers who participated found the app and data very useful. Another customer experience survey was conducted between October-November 2022. More than 25 trial participants completed the survey sharing their feedback. The questions in the survey revolved around the customer experience of being a part of this innovative trial. Key survey findings include: • Customers were asked to give a score out of 10 on their experience so far with the Community Battery trial. Customers who gave a score of less than 6 or below were considered detractors, those who gave a score of 7 or 8 were considered Passive, and those who gave a score of 9 or 10 were considered Promoters. Result were 13 promoters, 6 were detractors and the remaining 11 were passive • We asked the customers their reason for continued participation in the trial. Energy storage credits was the most selected motivator for continued participation. Participants have access to a smart measurement app that can be used to access their energy data. The energy data is visible through the app and an online portal that can be accessed during the trial period. While around 75% of customers found the data useful, the frequency of usage varied significantly among the respondents, ranging from once per day to once per month. Some customers never checked the app information. More information about the Community Battery trial and links to the research reports can be found at: https://www.ausgrid.com.au/sharedbattery
6	Battery Demand Response ("Power2U – Battery Virtual Power Plant Trial")	This project explored whether battery virtual power plants (VPPs) can provide reliable and cost competitive sources of demand reductions or voltage support services to defer network investment. The primary objectives of the project included: • Test whether customer battery systems offer a technically and commercially viable demand management option. • Test customer take-up of a network support (demand response) offer whereby customer battery systems are dispatched to align with network needs. • Investigate and trial the battery dispatch systems from market providers Secondary objectives included: • Better understanding of the types of customer battery systems being installed by early adopters of the technology. • Better understanding of the impacts on maximum demand and energy volume for a customer with a battery system with and without a demand response offer.

	Project Name	Project Description
		Phase 1 of the trial included collation and analysis of information of battery systems connected to Ausgrid's network and an exploration of possible offers and contractual arrangements with a range of different market providers (e.g. battery suppliers, aggregators and energy service providers). Phase 1 was completed in 2018-19. Phase 2 was initiated in late 2018-19 with customer trials. In the early stages of the customer trial, Reposit Power was selected as the VPP provider due to their proven experience with residential battery management and dispatch, significant experience with R&D and demonstration VPP projects, and their established customer base. A total of 237 customers were initially included in Ausgrid's VPP, representing an aggregated dispatch power capacity of 1MW and a storage capacity of 2.4MWh. In 2019-20, through an open tender process, Ausgrid added two additional VPP providers, Evergen and ShineHub. By the final year of the trial in 2021-22, Ausgrid's VPP fleet had grown to 750 residential battery with an aggregated dispatch power capacity of 3.4MW and storage capacity of 7.3MWh. This project concluded in June 2023. Key findings from the trial are outlined below: • A sufficiently sized VPP can help address network constraints during peak demand periods and potentially defer or avoid network upgrade. However, a significant increase in residential battery uptake is required for this potential to be realised. • While an orchestrated VPP dispatch can offer considerable additional power and demand reduction potential, residential batteries without VPP control ('business as usual' operation) can also reduce demand during peak periods, suggesting that a wider proliferation of residential battery will have a positive impact on demand management of the network. • A VPP can be used by multiple parties for different purposes, which could impact its availability during peak periods. It is important to coordinate and implement appropriate customer incentives, contracts, and systems to manage VPP availability. • While pre-charging the batteries is important for maximising VPP energy output, the timing of the pre-charging needs to be managed so that it doesn't add to network peak demand. For the customers, the benefits received from the dispatch need to sufficiently compensate for the cost of pre-charging. • Sending updated command signals throughout a dispatch can help optimise VPP dispatches by adjusting VPP behaviour to respond to changing conditions (e.g. load, available stored energy) however this requires a reliable communication network. • Both gross and net Feed-in-Management (FiM) can assist with lowering voltage during times of over voltage on the network however these options reduce customers' solar output, leading to financial loss for the customers. • Net FiM management is preferable to gross FiM as it allows the customer's load to be supplied by solar while restricting export into the grid. However, net FiM is more complex to implement because the inverter output must be constantly adjusted to supply the load but must be limited to prevent export exceeding a set threshold. • Participants' feedback for the trial was largely positive with most of the surveyed participants expressing that they're satisfied with their experiences with the trial and are likely to join a VPP again in the future. VPP trial findings, in particular the potential impacts that VPPs can have on the network, have helped informed our forecasting and planning processes. Lessons from Ausgrid's VPP project have also been incorporated into the design and approach for Project Edith, which explores how the grid can facilitate demand response energy solutions (such as VPPs) through the use of tools such as dynamic operating envelopes and dynamic network pricing. Information about the VPP project, including interim reports, can be found on Ausgrid's Demand Management web page for Innovation Research and Trials at https://www.ausgrid.com.au/Industry/Demand-Management/Power2U-Progam/Battery-VPP-Trial
7	Project Edith Customer Payments	This is a new DMIA project in the current 2019 to 2024 regulatory period. The project will continue into the 2023-24 year. Project Edith is exploring the effectiveness of dynamic network pricing to improve utilisation of distribution networks. If found effective, these price signals can reduce network costs to manage the impacts from minimum and maximum demand based on current and future trends, as well as improve customer outcomes such as reducing the need for curtailment of solar exports and unnecessary network upgrades. Importantly, achieving these outcomes will be primarily by effecting the behaviour of CER.

	Project Name	Project Description
		This project is critical research to ensure Ausgrid, other DNSPs and AEMO can identify how effective dynamic pricing signals are at influencing CER and consequently the future NEM. Project Edith has three primary objectives: 1. To test and demonstrate the effectiveness of managing network capacity through dynamic network pricing in a growing two-sided market. 2. To highlight and inform key areas in operationalising this model. 3. To engage and share insights within industry. The project sets out to meet these by developing an end-to-end dynamic pricing system including: • A pricing engine that can calculate dynamic network pricing considering internal (load measurements, metering data, network connectivity) and external (weather, aggregator operation) inputs, • An API that publishes 5-minute network pricing and operating envelope data to an aggregator on a day ahead and near real-time basis, and • A basic billing engine to determine the differential between the underlying network tariff and the dynamic network tariff for each Agent's customers. The intention for the first phase was to develop a proof-of-concept that could support up to 200 customers, primarily testing compatibility with existing systems to determine what investment in capabilities would be needed to scale the concept. The proof-of-concept was also intended to demonstrate dynamic pricing to stakeholders and contribute to policy discussions on how best to integrate CER into two-sided markets. The second phase will test a more robust sample of customer agents and customers. The DMIA project for customer payments supports these broader aims by providing a mechanism for the off-market tariff, allowing a lean and iterative research approach that could not have been achieved with an on-market trial tariff. This project is primarily funded through Ausgrid's Network Innovation allowance. The DMIA will be used to fund the customer savings realised by optimising for the off-market project tariff instead of their listed tariff. 2022-23 activities: Phase one of the project achieved its objectives by: • Validating the technical feasibility of an end-to-end solution for dynamic pricing, including a network model, pricing engine, and API integration. The project partner optimised their customers' solar and home battery systems around the dynamic network prices, showing that sophisticated tariffs for price-responsive devices can be implemented and add value for market-active customers. • Demonstrating that dynamic network pricing can be implemented through an evolution of existing systems, providing confidence in a cost-efficient implementation at scale. • Gaining support from stakeholders, including customer advocates, regulatory bodies, energy networks, energy retailers and aggregators, building confidence in dynamic network pricing as a way of generating value for networks and for virtual power plants and their customers. The customer payments facilitated through the DMIA allowed completion of the end-to-end experience and were thus crucial for this demonstration and stakeholder support. The demonstration faced several challenges. One of these was the effort required for Customer Agents to retrieve and optimise around the dynamic prices. Network prices have always been static in the past and applied in periods of no less than 30mins. Changes were made to their optimisation algorithms to accept 5-min variable network pricing, including both positive and negative values forecast a day ahead. Several iterations were needed to complete these changes and to identify and rectify issues that inevitably arise when sophisticated code undergoes such changes. This challenge was among the reasons for limiting the fully dynamic SRMC pricing to only five customers. The time needed for completing this work also limited opportunity to observe response to prices. The effort required also highlighted a potential challenge in recruiting further customer agents to the project. With substantial initial cost and effort required for a longer-term and uncertain benefit, it would be difficult for customer agents to prioritise participation. Greater support (in the form of co-funding) for this effort is possibly needed. Another challenge was the combination of capacity-based pricing with dynamic pricing. The project tariff included a capacity subscription which allows customer agents to reserve a minimum capacity

	Project Name	Project Description
		for each connection point, which is in effect a lower bound on DOEs that can be applied for that customer. Below the capacity subscription, usage charges were set to zero. This was intended to allow customer agents to optimise around customer assets depending on the level of available flexibility. During the trial we found that capacity subscriptions were set higher than we expected, due to the relative uncertainty around peak network use. This detracted from testing the dynamic prices since they were effectively zeroed for most of the time. This finding allowed us to pivot and move away from capacity subscriptions for the next phase of the project. Further work is required to establish the project's hypothesis is valid – that dynamic network pricing can be effective in managing network capacity in a growing two-sided market. A key element of this is determining price elasticity of customer energy resources, which requires both more participating customers and Customer Agents. Therefore, to ensure that project objectives are met, efforts are underway to increase the number of customer agents and customers participating. This expansion will explore a wider range of customer agents and the resultant customer offers they develop and offer a more robust sample of customer participation. Further information about Project Edith can be accessed on Ausgrid's website at https://www.ausgrid.com.au/About-Us/Future-Grid/Project-Edith.
8	Project Edith CSIP-Aus Specification Extension	This is a new DMIA project in the current 2019 to 2024 regulatory period. The project will continue into the 2023-24 year. This project proposes to develop, build, and test an extension to the currently published version of the CSIP-Aus API (Common Smart Inverter Profile – Australia, Application Programming Interface), that being version 1.1 dated June 2020. This extension is needed to provide the functionality required to communicate the dynamic network prices to customer agents (retailers and aggregators) in Project Edith. CSIP-Aus is being adopted by DNSPs across the NEM for the communication of dynamic operating envelopes (including flexible exports). The outcomes of a successful dynamic network service is expected to include increasing market participation opportunities for CER, increasing network utilisation, as well as enabling customers to provide more efficient demand management support services based on two-way dynamic pricing rather than direct procurement. This project is critical research to ensure Ausgrid, other DNSPs and AEMO can identify how effective dynamic pricing signals are at influencing CER and consequently the future NEM. This is possibly the first implementation of dynamic network pricing functionality in an API intended for CER communication; it is certainly the first in Australia. The objective of this project is to build and test an extended version of CSIP-Aus v1.1 that can communicate dynamic network pricing, and provide the specification, test results and insight gained to industry. While this work will be delivered within the broader goals of Project Edith, its deliverables are discrete and satisfy the eligibility criteria of DMIA funding. Therefore, this project's success will be in demonstrating that CSIP-Aus v1.1 can be appropriately extended to communicate Project Edith's dynamic network pricing concept. Validating the pricing concept remains with Project Edith. The expected outputs of this project are to 1. Develop a revised CSIP-Aus API specification that provides the necessary additional features and requirements to communicate dynamic network pricing in a way that is consistent with both CSIP and IEEE 2030.5; and 2. Build, test and validate an implementation of the revised API. Validating the API implementation will include integrating the API server into Project Edith's end-to-end testing with customers. This project is expected to be implemented in 2 phases: Phase 1 – CSIP-Aus specification extension The CSIP-Aus v1.1 specification will be extended to allow communication of dynamic network pricing. Care will be taken to achieve this by remaining within the guiding principles already established by the DER Integration API Technical Working Group who published the first CSIP-Aus specification. Principally this will be following the existing IEEE 2030.5 (which contemplates dynamic network pricing) and CSIP standards that inform CSIP-Aus. ANU will carry out this work. As subject matter experts on the current CSIP-Aus implementation, they are well placed to determine an extension that is consistent with both the guiding principles and standardisation of CER interoperability. Phase 2 – Build and test With the API specification now extended, Phase 2 will build an implementation and integrate it into the groups of systems Project Edith is using to demonstrate dynamic network pricing. Once

	Project Name	Project Description
		integrated, the API can be thoroughly tested, and the specification's extension validated. The timing of integration will largely be driven by other Project Edith activities. Therefore, results will be available according to that schedule. At the time of writing, it is anticipated that integration will have occurred by December 2023, and so testing and results gathering will occur after this. Once the specification extension has been implemented and tested, the results, specification extension and broader insights will be shared with industry. 2022-23 activities: <u>Phase 1</u>: A detailed examination of the IEEE 2030.5 standard has been conducted by ANU. Through discussions with Ausgrid, it was determined that the use of the "Pricing Function Set" within 2030.5 would be able to support the use cases of Project Edith without any extension or non-conformance. It is expected that this will be documented in a proposed amendment to CSIP-Aus following testing in Phase 2. <u>Phase 2</u>: ANU has built an initial implementation of an IEEE 2030.5/CSIP-Aus server with the 2030.5 Pricing function set within Ausgrid's information technology (IT) environment and with appropriate cybersecurity controls. This has been tested by ANU using a demo 2030.5/CSIP-Aus client which is able to register a connection point/device and retrieve dynamic network pricing information. Further testing will occur when aggregators have their first 2030.5/CSIP-Aus clients which are able to retrieve prices. ANU has prepared two documents providing information for software developers on integrating with their CSIP-Aus server: 1. Edith Client Development Quickstart – an introduction into Edith's use of a CSIP-Aus server. 2. Utility Server Client Development Guide – detailed description of implemented functionality. These documents have been included in Ausgrid' information package to aggregators/agents for the Project Edith expansion. Further information about Project Edith can be accessed on Ausgrid's website at https://www.ausgrid.com.au/About-Us/Future-Grid/Project-Edith.
9	Barriers to Electrification Study	This is a new DMIA project in the current 2019 to 2024 regulatory period. The project will continue into the 2023-24 year. This project aims to build Ausgrid's understanding of the impact of decarbonisation through electrification. The research will identify electrification pathways and explore how different social, economic, and technical customer barriers may impact different customer segments. A greater understanding of electrification will support electricity networks to explore how and when novel and innovative demand management techniques or smart and flexible technology solutions might facilitate the efficient addition of new electrical loads to the grid. The project is critical foundational research and is expected to support future network expenditure savings, lower average network charges per customer and effective prioritisation of future innovative trials for demand-side technology or demand management tariff and non-tariff interventions to enable efficient integration of new customer load and electrification. The objectives of the research are to: • Develop a prioritised list of customer barriers, based on external expert advice, rapid literature review and primary research including external stakeholder engagement. • Develop a better understanding for how the pace and scale of electrification might be influenced by a range of policy, social, economic, and technical customer barriers. • Identify opportunities or challenges for electricity networks, that guide priorities towards enabling efficient electrification and prioritise novel demand management opportunities. • Develop a better understanding of the potential for demand management tariff and non-tariff interventions that could be explored to integrate new load efficiently and support increased CER hosting capacity. This project will be delivered in 2 phases including: **Phase 1** This project will develop a prioritised list of the expected customer barriers and electricity network opportunities and challenges towards electrification. The project outcomes are expected to be organised into a report spanning the following topics:

	Project Name	Project Description
		• A current state landscape for decarbonisation relevant to Ausgrid's operating environment, including analysis on scale and pace of change and identify risks or uncertainties to likely electrification pathways. • A list of customer barriers to electrification, including the nature and materiality of barriers to unlock customer and whole of system benefits and/or outcomes. • A prioritised set of opportunities or challenges for Ausgrid and/or electricity networks to reduce the barriers identified or facilitate more efficient or accelerated electrification. • A prioritisation framework to guides investment timing and priorities in electrification research, and innovation. **Phase 2** The Phase 2 will be informed by the findings of phase 1, including project development to develop customer research and demand management trials to explore non-network tariff and non-tariff solutions identified through phase 1 to facilitate efficient customer electrification. Some of the possible customer trial activities might include: • Demand side solutions to support efficient least cost electrification for customers e.g. apartment buildings, including identification and assessment of network and non-network solutions (e.g. retrofitting for EV-ready buildings, gas to electric hot water systems) • Explore how electrification could be managed through development or trial of new network tariff structures or controlled loads. • Explore how electrification could be incentivised to increase network CER hosting capacity. • Explore demand side solutions to support efficient least cost electrification of social housing and potential barriers to lower costs for low-income housing customers. • Undertake longitudinal customer research on priorities and preferences relating to electrification and improved understanding of customer attitudes towards electrification of residential energy use and incentives. • Customer research and innovation into commercial or technical solutions that enable electrification for industrial or commercial loads and demand-side solutions for efficient integration of these loads to the network. 2022-23 activities: Through 2022-2023, an external consultant was engaged to support the delivery of Phase 1 of the Barriers to Electrification study. Activities completed include development of the current state assessment of electrification pathways through primary and secondary research, which included the development of customer barriers to electrification which were tested with external stakeholder groups. The external stakeholder consultations with a range of customer representative groups and industry were undertaken to understand and evaluate the needs of customers they represent including views and preferences relating to electrification and the barriers faced when considering adoption of electric appliances in place of gas or fossil fuels. The stakeholder engagement covered the following topics: Residential customers • Understand and confirm key residential electrification barriers. • Understand implications of residential electrification as flexible loads through new technologies • Understand levels of customer awareness, preferences and motivations for electrifying their home • Understand the customer expectations of electricity distribution networks to enable efficient electrification Commercial and industrial customers • Understand and confirm key commercial and industrial barriers to electrification for large energy users. • Understand opportunities, challenges and risks for high-energy users, including technology availability. • Existing load flexibility opportunities and technologies • Current approaches and challenges to achieving electrification and decarbonisation. • Understand customer expectations of electricity distribution networks to enable efficient electrification.

	Project Name	Project Description
		Electrification industry including Retailers, OEMs and representative bodies • Understand industry perspectives on barriers and opportunities of electrification via innovative technology and customer outcomes • Understanding customer sentiments and motivations to pursue electrification in the near-term • Understand the industry expectations of electricity distribution networks to enable efficient electrification. Outcomes of the stakeholder engagement and Phase 1 activities will continue to be developed and delivered through 2023-2024. Further activities will continue through the 2023-2024 regulatory year including identification of prioritised opportunities for Ausgrid to leverage demand management techniques to efficiently integrate new load and maximise use of renewable generation, which will be reported in future. If you have a specific information request regarding this project to assist in understanding, evaluating, or reproducing this project please contact demandmanagement@ausgrid.com.au.
10	C&I Thermal Flex	This is a new DMIA project in the current 2019 to 2024 regulatory period. The project will continue into the 2023-24 year. Ausgrid is seeking to assess the effectiveness of thermal load flexibility of C&I customers (thermal flex) in localised areas of Ausgrid's network. Medium to large energy demand from sites such as supermarkets, shopping centres and refrigerated distribution centres could potentially offer a material amount of load flexibility under both peak demand and minimum demand conditions. These loads are substantial in scale and commonplace in the community. The project will explore whether they can potentially offer an economic and reliable source of load flexibility. The primary purpose of the project is to determine the viability of thermal flex as a network demand management solution through building partnerships with 3rd party organisations and conducting customer trials. The objectives are to gain an understanding of: • Quantum and reliability of response acknowledging that thermal flex participants may also be participating in other market schemes; • Ability of provider to shape response to maximise network benefit; • Customer acquisition strategies and subsequent take-up of thermal flex; • Impacts from customer comfort/product requirements; • Customer experience; • Procurement and operating costs; • Viability as a BAU solution. The thermal flex project is expected to take place across 3 phases. The first phase commenced during 2022-2023 with negotiations progressing with one flex provider. **Phase 1** of this project includes the establishment of the collaborative thermal flex trial with 3rd party providers. Key activities involved setting up partnerships, establishment of trial agreements, setting out the trial outcomes and site selection. Ausgrid has undertaken analysis of the low voltage and high voltage network leveraging existing planning models to shortlist candidate areas of the network where thermal flex might provide near term network benefits. **Phase 2** of the DMIA project will involve field trials of thermal flex consistent with the project aims and expectations and evaluated using the approaches outlined below. **Phase 3**, as an optional phase and subject to the outcomes of Phases 1 and 2, could explore further activities to aid in development of the solution as a BAU process for managing network risk. 2022-23 activities: Project activity to-date includes initiation of discussions with one market provider of thermal flex during 2022-2023. As this DMIA trial progress further project activity updates will be provided in subsequent DMIA Annual Reports. If you have a specific information request regarding this project to assist in understanding, evaluating, or reproducing this project please contact demandmanagement@ausgrid.com.au.

3.4 Forecast demand management projects

Assessment for non-network solutions has determined that no projects were identified where it is was considered likely that demand management will would form part of the least cost solution to the need. This is principally due to the nature of these projects wherein all were related to replacement of aged assets.

Note though that the assessments for all projects were based upon preliminary assumptions for project costs, unserved energy and other benefits. A full assessment conducted as part of the RIT-D process, including a request for submissions via the Non-Network Options Report or equivalent, will occur in future. Refer to Section 2 of this report for the forward schedule for our RIT-D projects. In advance of the need date, a non-network options report will be published on Ausgrid's website at https://www.ausgrid.com.au/ritd.

3.5 Demand side engagement

During 2022 Ausgrid continued to inform and engage interested parties over a range of activities to improve demand management outcomes in meeting network needs.

Our main channel of engagement continued to be through our quarterly e-newsletters to inform stakeholders about our demand management initiatives, research and other relevant industry information. Past e-newsletters can be viewed on our Keep Informed page at https://www.ausgrid.com.au/Industry/Demand-Management/Demand-management-news.

In addition, we notified members on our demand management engagement register about our assessments on RIT-D projects and invited them to submit comments and proposals during the consultation process. This included notifications for 6 RIT-D project which can be viewed at:

https://www.ausgrid.com.au/Industry/Regulation/Network-planning/Regulatory-investment-test-projects

Our engagement activities also included our continuing memberships with the Clean Energy Council and Electric Vehicle Council.

For further information on our demand management programs and activities please contact Ausgrid's Demand Management team at demandmanagement@ausgrid.com.au.

For more information on how Ausgrid investigates and implements non-network solutions, please refer to our Demand Side Engagement Document at https://www.ausgrid.com.au/Industry/Demand-Management/Our-demand-management-strategy .

3.6 Embedded generator enquiries and connection applications

The following table summarizes embedded generation enquiries and applications that Ausgrid received under NER clause 5.3A.5, 5.3A.9, 5A.D.2 and 5A.D.3 during the financial year 2022-23.

Item Description	Quantity
Connection enquiries received under clause 5.3A.5	31
Applications to connect received under clause 5.3A.9	2
Average time taken to complete applications to connect	None Completed in FY22/23
Connection enquiries received under clause 5A.D.2 in relation to the connection of micro embedded generators or non-registered embedded generators	25
Applications for a connection service under clause 5A.D.3 in relation to the connection of micro embedded generators or non-registered embedded generators	39,561

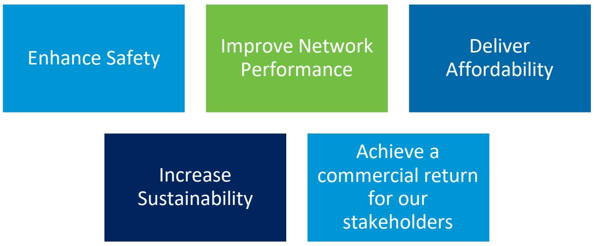
*Based on one complex connection application.

4. Asset Management

4.1 Ausgrid’s Asset Management Approach

The organisation’s vision is for communities to have the power in a resilient, affordable, net-zero future. Our asset management objectives are a key enabler of this vision.

These objectives are to:



Effective asset management practices will be applied across all levels of the organisation to deliver this vision. In providing services to our customers, we manage, operate and maintain a diverse and expansive electricity network. The following diagram outlines how Ausgrid’s asset management system structures our approach to apply a systematic, risk based, whole of life approach, which considers stakeholder requirements, regulatory frameworks and embeds continual improvement and innovation to continue to deliver on our strategic objectives in the context of an ever-changing operating environment.

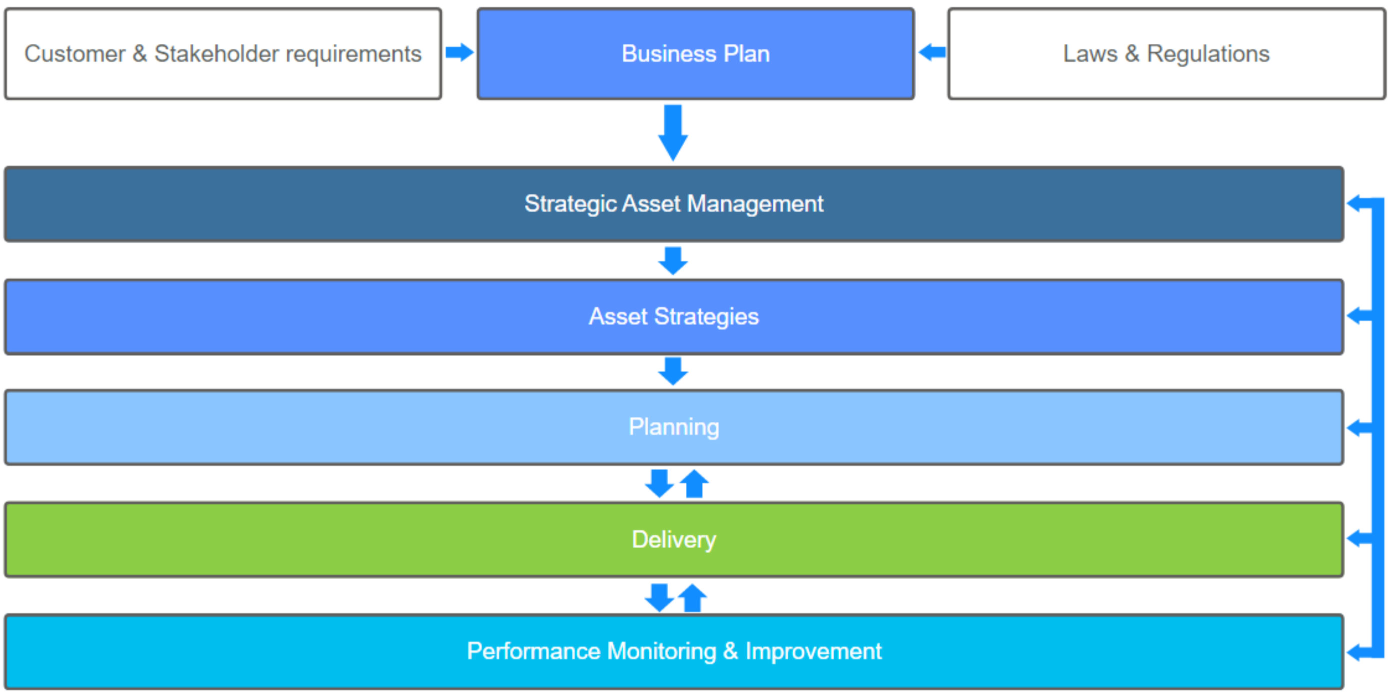


Figure 4-1: Overview of Ausgrid's Asset Management System

This approach also ensures we deliver and align with the National Electricity Objective and our regulatory and legal requirements, in particular obligations under the WHS Act 2011 and associated regulations, the Electricity Supply (Safety and Network Management) Regulation 2014 (NSW), the National Electricity Law (NEL) and the Electricity Supply Act 1995 (NSW).

Our asset management system, including the strategies, models and processes adopted by Ausgrid, has been certified to conform with the requirements of AS ISO 55001:2014 Asset Management – Management Systems – Requirements in accordance with our Distribution Licence Conditions.

This structured approach to asset management ensures that we continue to deliver on our vision and meet the goals of our customers, shareholders and employees.

4.2 Risk Management Strategies

The asset management objectives captured within the Asset Management System align to the organisation's objectives and risk appetite. Asset decisions are informed through structured risk assessments in accordance with the Risk Management Board Policy and Risk Management Framework. Ausgrid's asset management approach utilises risk management techniques to manage risk within the organisation's Risk Appetite Statement.

Risk management techniques applied to inform asset decision making consistent with the organisation's legislative responsibilities and AS/NZS ISO 31000-2018 Risk Management – Principles and Guidelines for managing risk. Ausgrid applies numerous techniques for managing risk at various scales, leading to various decision pathways across the life cycle of an asset. The asset management system draws on AS/NZS IEC 31010:2020 Risk management — Risk assessment techniques (IEC 31010) to guide a structured approach to decision making. Risk management techniques such as reliability centred maintenance and cost benefit analysis are used to evaluate risks and determine maintenance and investment requirements respectively.

An overview of significant asset class investment strategies is outlined in the following sub-sections.

4.2.1 Sub-transmission underground cable strategy

Ausgrid's sub-transmission cables are an essential part of our supply network. Ausgrid has approximately 1,103km of sub-transmission cables with the majority operating at either 33kV or 132kV and a small number at 66kV.These assets cannot routinely be taken out of service except for brief periods necessitated by the need for maintenance and repair, particularly those which operate at 132kV supplying the inner metropolitan area of Sydney.

There are four cable technology types used for these cables – these are listed below (from oldest to youngest type):

- 194km of self-contained fluid filled ('SCFF') cables;
- 38km of gas pressure cables;
- 229km of paper insulated, lead covered ('paper lead') cables; and
- 640km of cross-linked polyethylene ('XLPE') cables.

Approximately 50% of Ausgrid sub-transmission cables operate at 132kV and many of these form the critical backbone of the sub-transmission network. Failure of multiple 132kV cables can have significant impacts upon our customers, particularly in the Sydney CBD and surrounding urban areas.

A risk assessment has been undertaken on our sub-transmission cables using an asset failure probability model and consequence assessment, with timing of any retirement decision based on cost benefit analysis. From the assessment, SCFF and gas pressure cables are approaching end of life and have been forecast for retirement / replacement over the next 15-20 years.

SCFF cables operate at 132kV. Due to the environmental risks posed by these cables, Ausgrid consults with the Environmental Protection Agency (EPA) to take reasonable steps and exercise due diligence regarding the management of the environmental risks. The cost benefit analysis takes into consideration:

- the unavailability of individual SCFF cables (failure probability),
- condition of individual SCFF cables primarily based on their level of fluid leakage and the condition of the cable,
- network restoration and repair times for failures and defects,
- the environmental risk from individual cables, in particular those crossing major waterways, and
- the unserved energy (customer reliability impacts) which are realised in the event of an asset failure.

Gas pressure cables equate to approximately 3% of Ausgrid sub-transmission cables and they all operate at 33kV. The failure of mechanically fatigued joints, degradation of the cable system resulting in increasing gas leakage rates and the lengthy restoration and repair times, support the retirement of gas pressure cables. As supported by cost benefit analysis, retirement of all remaining gas pressure cables is expected in the next 20 years.

Ausgrid also has a substantial population of paper lead cables which all operate at 33kV. These cables formed the backbone of the sub-transmission network at its inception and remain relatively reliable despite their age, with some sections up to 95 years old. The lifespan of these cables is generally considered to be approximately 80 years; however, individual circuits may be retired prior to reaching this age based on condition (issues related to corrosion of the lead sheath or loss of resistance in the paper insulation) as supported by cost benefit analysis and other network needs.

XLPE cables are the current technology being installed for 33kV, 66kV and 132kV circuits. Ausgrid has been utilising this cable technology for approximately 30 years and is expecting a 60-year operating life. There are currently no plans to retire these assets within the planning horizon.

4.2.2 11kV switchgear strategy

Between the late 1930s and the early 1970s Ausgrid progressively installed a large number of compound insulated 11kV switchboards with bulk oil circuit breakers (OCB). As technology progressed, air insulated switchboards (non-internal arc classified technology) with bulk oil circuit breakers (OCBs) became widely available and were installed from the late 1960s until the late 1970s, when vacuum circuit breakers (VCB) were introduced. From 2004, internal arc classified switchgear became the accepted industry standard for new installations. This progression of technology has resulted in a corresponding reduction in the risk of catastrophic failure (both likelihood and consequence). This reduction in risk was traded off against a larger construction footprint in a typical urban style Zone Substation.

In rural and lower loaded areas, outdoor 11kV switchgear (cubicle or recloser style) has generally been used as this is a more economical design than indoor switchgear in those areas. However due to the increased exposure to local environmental conditions, this type of switchgear has deteriorated over time, leading to more frequent failures and higher maintenance costs.

Risk assessments considering likelihood and consequence have been conducted on 11kV indoor switchgear. Application of cost benefit analysis to the age and condition issues associated with 11kV compound switchboards, confirm that these are approaching end of life. Switchgear risks are considered in conjunction with other planning needs in the local area to determine the optimal replacement timeframes, with consideration given to work bundling opportunities. The cost benefit analysis takes into consideration:

- the unavailability of individual switchboards / switchboard sections,
- condition of individual components primarily based on maintenance test results,
- network restoration and repair times for failures and defects,
- the risks from switchboard failures, and
- the unserved energy (customer reliability impacts) which are realised in the event of an asset failure

Oil filled circuit breakers pose an additional risk to safety, reliability and secondary asset damage due to the catastrophic nature in which they can fail. To mitigate this risk and defer retirement of older style air insulated switchboards, 11kV oil filled circuit breakers in zone substations have largely been replaced with vacuum equivalents where practical.

4.2.3 Additional replacement programs

Additional key replacement programs include:

- Condition based replacement of poles,
- replacement of higher risk overhead conductor types,
- reconfiguration of low voltage streetlight mains (conversion to regular mains supply), and
- replacement of low voltage underground cable types with conditions/reliability issues.

4.3 Distribution network losses

Distribution network losses refer to the difference in energy obtained from the transmission network to that supplied to customers. Ausgrid's distribution network losses as a percentage of total energy for the 2021/22 financial year was 3.46%[7].

Electrical energy losses represent a cost to network service providers and customers, and therefore it is Ausgrid's objective to minimise these losses, while maintaining a safe and reliable electricity supply, at minimum cost to the community. When considering potential network projects under the NER's Regulatory Investment Test for Distribution, Ausgrid must consider changes in electrical energy losses if they are material or may alter the selection of a preferred investment option.

Ausgrid's methodology for calculating losses is published on its website as part of the requirements of the NER to maintain a method for calculating Distribution Loss Factors (DLFs). This methodology is to utilise the Incremental Transmission Loss Allocation where losses to specific load or generation points are allocated according to its effect on the total losses of the system. The aim of this methodology is to enable the quantification of incremental values of network loss savings in the assessment of proposed network project options, and the quantification of network losses as required under the RIT-D. Additionally, the methodology enables the calculation Distribution Loss Factors (DLF) for Individually Calculated Tariffs (ICT) customers and embedded generation systems.

Ausgrid's technical specifications for the assessment of losses for primary plant such as subtransmission transformers, distribution transformers, shunt reactors etc, specify the method of assessing capitalised losses when comparing tender offers from suppliers.

4.4 Obtaining further information on asset management

Further information on asset management may be obtained from Ausgrid's Asset Management Policy (available on request from the Group Executive – Customer, Assets & Digital), and our Electricity Network Safety Management System (ENSMS) Annual Performance Report available on the Ausgrid website.

[7] The distribution network losses are reported at the end of each calendar year, using the previous financial year's accumulated loss data.

5. Network Performance

5.1 Reliability Measures and Standards

Ausgrid seeks to comply with regulatory requirements at reasonable costs, given the condition and utilisation of existing network assets and the funding available to maintain and augment the electricity network.

Under the NSW Reliability and Performance (R&P) Licence Conditions for Electricity Distributors[8], Ausgrid is required to comply with specific targets for reliability standards and individual feeder standards. The purpose of the licence conditions is to facilitate the delivery of a safe and reliable supply of electricity. Ausgrid is required to report to the Minister to ensure compliance with the R&P licence conditions.

Under the National Electricity Rules (NER), and the Service Target Performance Incentive Scheme (STPIS), Ausgrid is given financial incentives to improve customers' reliability performance compared to historic outcomes over time (as well as penalties if the performance level deteriorates).

Reliability measures used are SAIDI (System Average Interruption Duration Index), or minutes off supply for the average customer, and SAIFI (System Average Interruption Frequency Index), or number of interruptions experienced by the average customer. The reliability performance is monitored at distribution feeder level for unplanned interruptions (excluding major event days, planned interruptions and circumstances beyond the reasonable control of the electricity distributor).

The individual feeders are categorised as CBD (Sydney CBD), Urban, Short Rural, Long Rural and Low Voltage Stand Alone Power Supplies (LV SAPS). This is based on feeder length, load density and connectivity. Ausgrid distribution network consists of 56 CBD feeders, 1896 Urban feeders, 411 Short Rural feeders, 5 Long Rural feeders, and 3 LV SAPS. 82% of Ausgrid's customers are connected to Urban feeders.

Our customers must plan around the possibility that the electricity supply may not always be available and that interruptions could occur without notice, or with notice in accordance with their supply contract.

5.1.1 Supply Reliability Standards

Average Feeder Category Reliability Standards

The purpose of the R&P licence condition Section 6.1 – "Network Overall Reliability Standards" is to:

- define minimum average reliability performance, by feeder type, for a distribution network service provider across its distribution network, and
- provide a basis against which a distribution network service provider's reliability performance can be assessed.

Average Reliability Standards

	CBD	Urban	Short Rural	Long Rural
SAIDI	45	80	300	700
SAIFI	0.30	1.20	3.20	6.00

Individual Feeder Standards

The purpose of the R&P licence condition Section 6.2 – "Individual Feeder Standards" is to:

- specify minimum standards of reliability performance for individual feeders;
- require a distribution network service provider to focus continually on improving the reliability of its feeders, and
- enable the reliability performance of feeders to be monitored over time.

Individual Feeder Standards

	CBD	Urban	Short Rural	Long Rural	LV SAPS
SAIDI	100	350	1000	1400	1817
SAIFI	1.4	4	8	10	9.4

Individual Customer Standards

The purpose of the R&P licence condition Schedule 8 – "Individual Customer Standards" is to:

- specify minimum standards of reliability performance for individual customers;
- require a distribution network service provider to focus continually on improving the reliability of its customers, and
- enable the reliability performance of customers to be monitored over time.

Individual Customer Standards

	Minutes Interrupted	Number of Interruptions
Metro	350	4
Non-metro	1000	8

[8] The Minister for Energy established licence conditions for distribution network service providers on 1 August 2005 (revised December 2007, July 2014,for the Ausgrid Operator Partnership ("Ausgrid") on 1 December 2016, and for the operator of a transacted business on 4 December 2017. These were further amended in February 2019, October 2022 and September 2023). See: https://www.ipart.nsw.gov.au/Home/Industries/Energy/Energy-Networks-Safety-Reliability-and-Compliance/Electricity-networks/Licence-Conditions-and-Regulatory-Instruments

5.1.2 Network Supply Reliability Performance in the Preceding Year

SAIDI & SAIFI Performance

The following graphs depict the normalised (i.e. Major Event Days data excluded) SAIDI and SAIFI trends over the period 2010/11 to 2022/23.

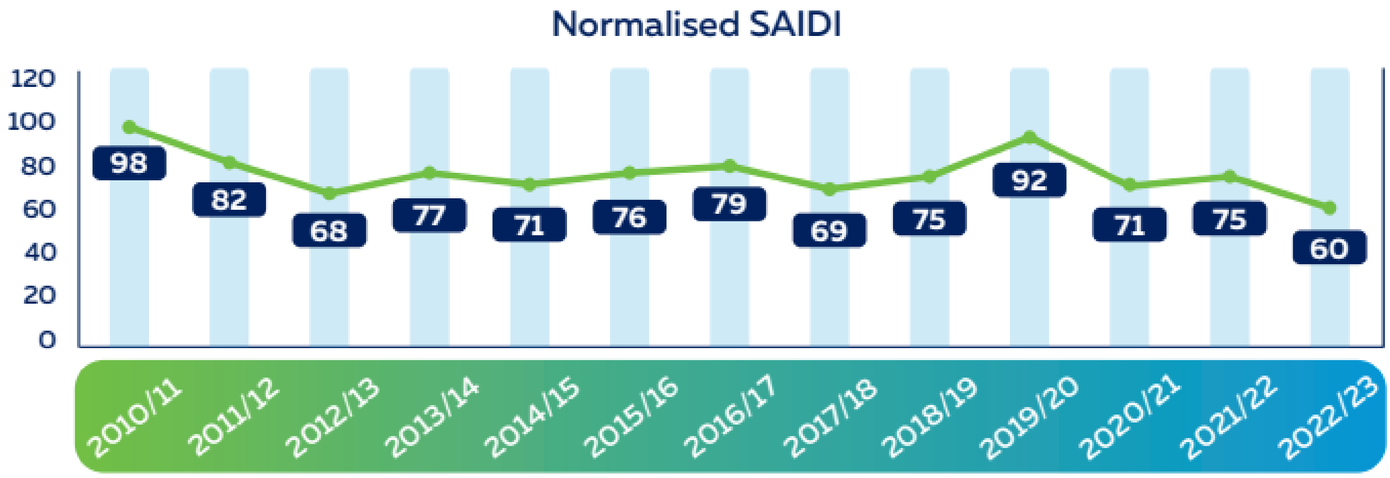


Figure 5-1: Global unplanned SAIDI

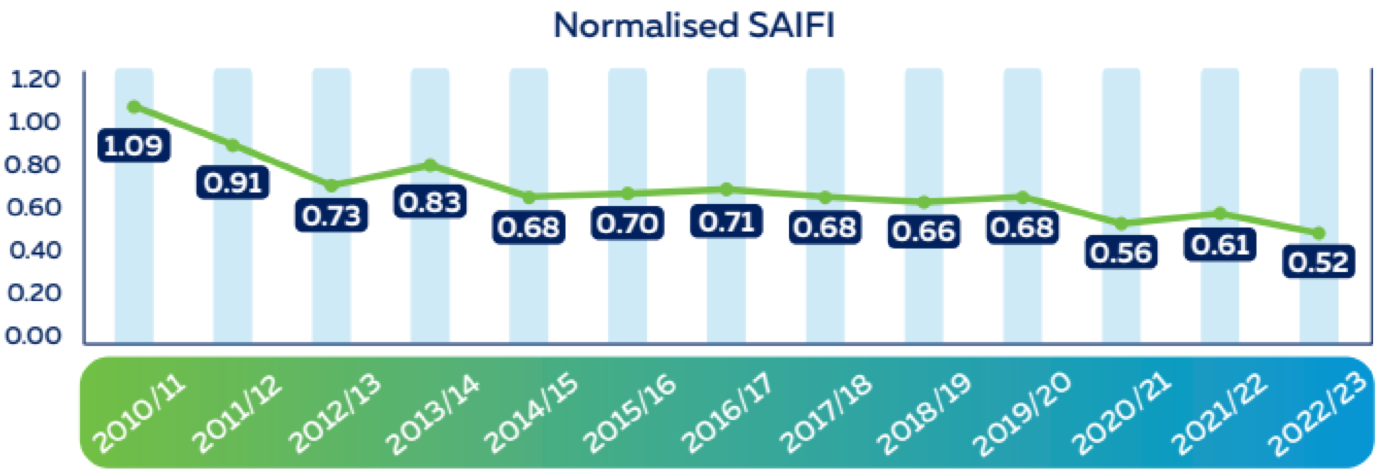


Figure 5-2: Global unplanned SAIFI

Major Event Days

Ausgrid uses the methodology described in IEEE 1366 standard for defining Major Event Days, as outlined in the R&P licence conditions and AER STPIS Definitions.

There were four Major Event Days for 2022/23.

Major Event Days During 2022/23

Date	Excluded SAIDI	Cause of Major Event Day
3/07/2022	5.49	Storm
5/07/2022	10.21	Storm
9/02/2023	3.69	Storm
18/02/2023	6.18	Storm

Individual Feeder Reliability Performance

As required under the R&P Licence Conditions for Ausgrid, each feeder currently exceeding the Individual Feeder Standard is analysed and an investigation report identifying the causes and, as appropriate, any action required to improve the poor performance is reported in the next quarterly performance report. The majority of feeder exceedances were determined to be random events and action was limited to monitoring ongoing reliability performance. A small number of feeders required remedial actions such as vegetation management and repairs to network assets or capital works.

All required actions were completed in the timeframes required.

Ausgrid has an ongoing reliability management program that targets those feeders that have exceeded the Individual Feeder Standards as outlined in Schedule 3 of the R&P Licence Conditions. The individual feeder performance against the standard is given in the table below.

Individual feeder performance against the standard FY23

	CBD	Urban	Short Rural	Long Rural	SAPS
Feeders (Total Number)	56	1,896	411	5	3
Feeders that Exceeded the Standard during the Year	3	43	4	2	0
Feeders Not Immediately Investigated	0	0	0	0	0
Feeders Not Subject to a Completed investigation report by the Due Date	0	0	0	0	0
Feeder Not having Identified Operational Actions Completed by Due Date	0	0	0	0	0
Feeders Not having a Project Plan Completed by Due Date	0	0	0	0	0

Feeder Categories Reliability Performance

All feeder category performances were compliant against the NSW R&P Reliability Standards.

Whole Organisation and Feeder Category reliability performance

12-month period to end of June 2023							
		ORG*	CBD	Urban	Short Rural	Long Rural
SAIDI	Actual	59.62	11.69	52.96	91.90	909.35
SAIDI	Licence Conditions standard		45	80	300	700
SAIFI	Actual	0.52	0.05	0.47	0.79	3.02
SAIFI	Licence Conditions standard		0.3	1.20	3.20	6.00

Note: * Refers to the average performance of the organisation overall. This measure does not form part of the licence conditions but is needed to calculate the overall NSW result.

Ausgrid's 2022/23 performance results were within the required levels for all metrics except Long Rural SAIDI. Floods in early July 2022 affected the fault identification and restoration of the outage for several days. We are progressing with our remediation plan previously shared it with IPART.

Individual Customer Standards Performance

As required under the R&P Licence Conditions for Ausgrid, customers currently exceeding the Individual Customer Standard is analysed and an investigation report identifying the causes and, as appropriate, any action required to improve the poor performance is reported in the next quarterly performance report.

The individual customer performance against the standard is given in the table below.

Individual Customer performance against the standard during 2022/23

	Metro	Non Metro
Customers that Exceeded the Standard during the Year	1	0
Customers Not having a Project Plan Completed by Due Date	0	0

A project to improve the reliability of the customer via the installation of field reclosers on the feeder, was completed in late 2020.

5.1.3 Service Target Performance Incentive Scheme (STPIS)

The Australian Energy Regulator's (AER) distribution Service Target Performance Incentive Scheme (STPIS) provides a financial incentive for Ausgrid to maintain or improve its reliability and customer service performance over time. As part of the AER final determination for Ausgrid, the AER set elements of the STPIS for the 2019/20 – 2023/24 period including at-risk revenue caps, reliability targets, and customer service targets. The revenue at risk for each regulatory year is capped at 5 percent with a 4.5 percent cap for the reliability of supply component and 0.5 percent cap for the customer service component.

The SAIDI and SAIFI targets set by the AER in their final determination for each feeder category for the reliability component of the STPIS are set out in the tables below[9].

STPIS results – Unplanned SAIDI Targets vs Actuals

	2021/22		2022/23	
	Target	**Actual**	**Target**	**Actual**
CBD	9.09	6.15	9.09	11.69
Urban	59.91	62.94	59.91	52.96
Short Rural	127.96	130.64	127.96	91.90
Long Rural	496.12	1563.16	496.12	909.32

STPIS results – Unplanned SAIFI Targets vs Actuals

	2021/22		2022/23	
	Target	**Actual**	**Target**	**Actual**
CBD	0.038	0.01	0.038	0.05
Urban	0.603	0.55	0.603	0.47
Short Rural	1.139	0.93	1.139	0.79
Long Rural	2.481	2.04	2.481	3.02

5.1.4 Forecast Of Network Reliability Performance

Ausgrid's Reliability Forecasting System (RFS) forecasts the reliability performance of each feeder category based on 5 years of historical performance.

Average minutes of supply interruption per customer per year

SAIDI	**2023/24**
System	**74**
CBD	**13**
Urban	**65**
Short Rural	**129**
Long Rural	**841**

Average number of network interruptions per customer per year

SAIFI	**2023/24**
System	**0.69**
CBD	**0.04**
Urban	**0.56**
Short Rural	**0.93**
Long Rural	**2.27**

Where a shortfall in reliability is identified for feeder category performance, improvement methods may include:

- improvements of individual feeder performance - affecting a sufficient number of individual feeders to influence the category average, or
- Improvements at a sub-transmission level, or
- Improvements with widespread impacts such as operating policy and its implementation, SCADA systems, and the development of intelligent network options.

Project proposals within these three categories are short-listed and the anticipated cost benefit of each option is estimated. The cost estimates are based on standard unit costs and adjusted to reflect, to the extent practicable, the realities of implementing the solution.

5.1.5 Compliance with Network Reliability Standards

Ausgrid monitors feeder outages and records the duration of outage events into the Outage Management System (OMS). For reliability reporting purposes, the network performance is measured at the distribution feeder level.

Excluding any excluded events, including planned interruptions and Major Event Days, the recorded outage information provides Ausgrid with the frequency and duration of feeder outages that are used to determine the SAIDI and SAIFI of individual feeders. In turn these individual feeders are grouped into categories, to enable an average SAIDI and SAIFI to be determined for each feeder category (CBD, Urban, Short Rural and Long Rural).

Every quarter Ausgrid submits a report stating the business performance against the overall Reliability, Individual Feeder and Customer Service Standards to IPART and the Minister administering the Electricity Supply Act 1995 within one month of the end of each quarter.

The report lists performance against the pro-rata SAIDI and SAIFI average standards, along with any reasons for non-compliance and Ausgrid's plans to improve the feeder performance. Similarly, the

[9] Table extracted from the AER's Final Decision Ausgrid Determination 2019-24 Attachment 10 Table10.2 – Service Target Performance Incentive Scheme.

Individual Feeder document details the date at which a feeder first exceeded the relevant Individual feeder standard and the SAIDI and SAIFI performance for that 12 month period, including details of the remedial action to be taken to improve performance, and the planned date of completion for the action plan. Typical remedial action plans include either operational and/or capital expenditure, or alternatively there is the option of a non-network solution.

Operational work may include works like vegetation maintenance or retro-fitting of animal proofing on electrical mains and apparatus. Any identified and reported operational work is due to be completed by the end of the third quarter following the feeder first exceeding the individual feeder standards.

Capital expenditure to improve feeder reliability can be in the form of a network augmentation project involving feeder reclosers or covered overhead mains to prevent or correct some known outage triggers. Any required capital work is to be developed, planned and commenced by the end of the second quarter following the feeder first exceeding the individual feeder standards. Some investigations find that a feeder outage occurred due to a one-off event that is not likely to occur again.

Non-network solutions may include energy storage systems to provide ride-through capability during outages.

5.2 Quality of Supply Standards

Ausgrid's makes best endeavours to provide a service that meets quality of supply standards of our electricity network within available funding, asset conditions and utilisation. Ausgrid's network standard NS 238 Supply Quality[10] sets out Ausgrid's standards for Quality of Supply which customers can expect from Ausgrid's network covering the performance of the network in terms of steady state voltages, voltage unbalance, harmonic distortion, and rapid voltage variation. The quality of supply is determined by the characteristics of connected loads, the network configuration and network events.

Ausgrid does not control the frequency on the electricity supplied through its electricity network, as this standard is set during the electricity generation process. The Australian Energy Market Commission (AEMC) establishes standards and regulates the frequency of supply[11] on the national grid.

5.2.1 Voltage Range for Supplied Electricity

Supply voltage is the voltage, from phase to neutral or phase to phase, for electricity that is supplied at a customer's point of supply. Maintaining the steady state supply voltage is important to ensure the customer experience, and the efficiency and stability of the network. When Ausgrid identifies or is notified that the steady state supply voltage is outside the specified target range, Ausgrid will investigate by carrying out relevant measurements on the network in conjunction with the existing network monitoring to determine the remediation necessary. An increase in solar PV installations made steady state voltage the most prominent quality of supply parameter.

Low Voltage Network

Ausgrid's objective for the operation of its network is to maintain a target steady state phase to neutral supply voltage (measured as a ten-minute average) within the range of 216V to 253V at customers' points of supply under normal operating conditions. This range is the nominal voltage range of 230V as defined in the relevant Australian Standard AS 61000.3.100, with a tolerance of +10% / -6% to allow for voltage regulation on the mains between distribution substations and customers' points of supply.

The 99th percentile (V99%) of the 10-minute average voltage readings for a 1-week survey should be less than 253V and the 1st percentile (V1%) should be greater than 216V.

High Voltage Network

Ausgrid's high voltage distribution network operates at several voltage ranges. Accordingly, high voltage customers must obtain from Ausgrid the network operating objective for supply voltage applicable to their location, particularly before proceeding with any project expenditure or commitments.

Applicable Quality of Supply Codes, Standards and Guidelines

Ausgrid relies on the following standards and/or guidelines when setting and assessing network voltage performance:

- Network Standard: NS 238 Supply Quality
- Australian Standards: AS/NZS 60038 and AS 61000.3.100
- NER S5.1a.4 – Power Frequency Voltage
- NSW Service and Installation Rules (SIR): Section 1.11.1 refers to AS/NZS 600038 & AS 61000.3.100.

5.2.2 Harmonics and Total Harmonic Distortion

Voltage waveform distortion including harmonic distortion results from the operation of appliances or equipment that draw non-sinusoidal currents from the network. Harmonic distortion can cause the supply voltage to depart from a sine wave in a repetitive manner. Maintaining waveform distortion within acceptable limits is important because it can otherwise cause interference and damage to sensitive customer and network equipment. This form of distortion can also cause light flicker, incorrect operation of ripple control devices (used for off peak electric hot water) and computers, audible noise in television, radio and audio equipment and vibration in induction motors.

Applicable Quality of Supply Codes, Standards and Guidelines

Ausgrid relies on the following standards and/or guidelines when limiting and assessing harmonic performance:

- Network Standard: NS 238 Supply Quality

[10] https://www.ausgrid.com.au/-/media/Documents/Technical-Documentation/NS/ns238.pdf

[11] https://www.aemc.gov.au/australias-energy-market/market-legislation/electricity-guidelines-and-standards/frequency-0

- Australian Standards: TR IEC 61000.3.6:2012, AS 61000.2.2:2023, AS 61000.3.12:2023, SA/SNZ TR IEC 61000.3.14:2013
- NER S5.1a.6 – Voltage Waveform Distortion
- NSW Service and Installation Rules (SIR): Section 1.17.2.1 (b) refers to AS/NZS 61000.3.2, 61000.3.4, 61000.3.12.

5.2.3 Voltage Fluctuations (Flicker) – Applicable Quality of Supply Codes, Standards and Guidelines

Ausgrid relies on the following standards and/or guidelines when limiting and assessing Voltage fluctuations performance:

- Network Standard: NS 238 Supply Quality
- Australian Standards: TR IEC 61000.3.7:2012, AS 61000.2.2:2023, AS 61000.3.12:2023, SA/SNZ TR IEC 61000.3.14:2013
- NER S5.1a.5 – Voltage Fluctuations
- NSW Service and Installation Rules (SIR): Section 1.17.2.1 (b) refers to AS/NZS 61000.3.3, 61000.3.5, 61000.3.11.

5.2.4 Voltage Unbalance – Applicable Quality of Supply Codes, Standards and Guidelines

Ausgrid relies on the following standards and/or guidelines when limiting and assessing Voltage Unbalance performance:

- Network Standard: NS 238 Supply Quality
- Australian Standards: TR IEC 61000.3.13:2012, AS 61000.2.2, AS 61000.2.12, SA/SNZ TR IEC 61000.3.14:2013
- NER S5.1a.7 – Voltage Unbalance.

5.3 Quality of Supply Performance for Preceding Year

At Ausgrid, monitoring for supply quality is undertaken by a number of means including review of customer complaints, permanent monitoring at selected locations across the network, power quality data from customer smart meters, and participation in the National Power Quality Compliance Audit conducted by the Australian Power Quality Research Centre (APQRC) at the University of Wollongong.

Ausgrid has been actively using power quality data from the smart meters. These measurements are used to assess compliance and proactively manage steady state voltage performance especially in the areas with high solar PV density.

5.3.1 Supply Voltage Performance

Distribution substations with Voltage monitoring showed 100% of sites met the V1% limit (216 Volts) and 95% of sites met the V99% limit (253 Volts).

In turn, Smart Meter measurements shows that 8% of sites are non-compliant for V99% voltage, 2% of site indices are non-compliant for V1% voltage while 70% of sites were within aspirational range for V50%. While a significant percentage of sites exceed the limit, the magnitude of the exceedance is relatively small. There is evidence of voltage peaking in the early morning and the middle of the day which can be attributed to the solar PV. Voltage is lowest during the evening peak load periods. As stated in the next section 5.4 (Corrective Action) Ausgrid has an ongoing reactive program to lower network voltages towards the nominal 230V standard as issues are identified on the network.

In recent years, the high penetration of solar generation has resulted in localised high voltage issues generally observed by customers experiencing loss of energy exports due to inverter behaviour as prescribed under AS/NZS 4777. During the reporting period 366 technical quality of supply complaints were received, approximately half of which are solar related. In most cases these were resolved by either changing the Power Quality response modes of the customer's inverter(s) as specified in AS/NZS 4777.2 or by way of 'tap changes' on the customer's supplying transformer.

5.3.2 Harmonic Content of Supply Voltage Waveform

There were no complaints registered for harmonic issues.

5.3.3 Voltage Fluctuations (Flicker) Performance

There were several complaints registered as being about flicker. None were confirmed to be flicker or fluctuations within the definition of TR IEC 61000.3.7 standard, but rather light flicker caused by ripple control signals for controlling Off peak Hot Water systems.

5.3.4 Voltage Unbalance Performance

Overall, there are no significant issues, however, unbalance levels in some areas approaching the limit.

5.4 Corrective Action Planned to Meet Quality of Supply Standards

5.4.1 Supply Voltage

Ausgrid's voltage management has matured in recent time moving away from a reactive approach with peak demand focus to a more proactive approach with focus over the demand cycle. This maturing has been influenced by the changing use of our network, changing customer energy profile and, and to a great extent to prepare our network for continued change.

Voltage management has several dimensions including;

- Change underlying network ability to host load and generation: network assets, network performance and modelling
- Making sure connections can operate together: connection policy and customer device settings

- Managing DER behaviour: DER management and tariffs and pricing
- Smart devices to smooth the impact of customers behaviour: STATCOMs, community batteries and grid batteries

Our Voltage Management Plan includes a holistic end to end approach considering all levels of our network from our connection with TransGrid through to our low voltage customers. This provides an understanding of options available at all network levels and allows for the most efficient option to be identified.

Proactively monitoring voltage data from various sources combined with customer complaint data provides a view of our network voltage health. This data provides feedback into our voltage regulation planning: where emerging and forecast issues are identified we can proactively determine options and implement the most efficient option.

Measurements on the LV network indicate that several sites exceed the V99% target voltage as specified in AS 61000.3.100. This year, Ausgrid also added Smart Meter voltage measurements taken at the customer metering points. However, Smart Meters measurements are largely inclined towards solar installations.

As part of the 230 Volt transition Ausgrid is currently undertaking numerous activities to improve voltage across the network and deliver network functional compliance:

- Development of additional analysis tools combining network models with measurements to address voltage challenges due to increasing DER capacity.
- Lowering of the zone substation 11kV float voltages.
- Change of distribution transformer tap settings to deliver the correct 99th percentile voltage (to AS 61000.3.100). Tap setting changes are carried out in conjunction with other maintenance works to constrain costs to the community. Tap setting changes will be carried out earlier in the case of customer complaints that are identified to be due to higher voltages at the distribution transformers (for example where a customer has installed a PV Solar system that is limiting export due to AS/NZS 4777 settings). In some cases where transformers have insufficient tapping range or because of physical condition of the transformer, a replacement will be carried out.

5.4.2 Flicker, Harmonic and Unbalance

Ausgrid monitors customer complaints and resolves any supply quality issues as they arise.

5.5 Compliance with Quality of Supply Standards

Under the Standard Form Customer Connection Contract with Ausgrid, our low voltage network customers are required to comply with the requirements of the Service and Installation Rules of NSW and any other reasonable Ausgrid requirements. Consistent with those Rules and our rights under the Contract, Ausgrid requires our customers to ensure that:

- their electrical installation does not adversely affect Ausgrid's network or other customers' installations, and
- that any audible or electronic noise generated by their electrical installation does not breach relevant laws or adversely affect others. If disturbances on the network are caused by more than one customer, Ausgrid will establish overall limits for the interference by each customer, and customers who exceed their limits are required to rectify the situation.

Ausgrid's network modelling process includes checks for voltage compliance on the high voltage network and our internal standards specify compliance requirements for low voltage. Customer quality of supply complaints are reviewed, and corrective action taken as necessary.

The process for managing supply quality emission limits for major customer connections is generally dictated by the National Electricity Rules (NER) requirements for connection agreements. Ausgrid is required to provide a 20-day turnaround on responses to connection enquiries under the NER. Limits for automatic and minimum access standards for supply quality are included in Ausgrid's response to the connection enquiries. There are different rules which apply to network customers and registered generators. However, generally the allocation of emission limits for customers and generators are defined in NER clauses S5.1.5-5.1.7. Supply quality requirements for connections are based around the following access standards:

- Automatic Access Standards
- Minimum Access Standards
- Negotiated Access Standards.

For Generators, allocation limits are defined according to NER Clauses S5.2.5.2. For network customers, allocation limits are defined according to NER Clauses S5.3.7 and S5.3.8.

For both generators and customers, harmonic and flicker allocations are based on the AS/NZS 61000.3.6 & 61000.3.7 series of documents. For voltage unbalance the proposed approach within Ausgrid is to follow (SA/SNZ) TR IEC 61000.3.13, which mirrors the Stages 1-3 approach of the harmonic and flicker standards.

The process for achieving compliance with the prescribed supply quality allocation limits is likely to be an iterative process, with consideration given to alternative connection points, or mitigation measures, should initial investigations indicate non-compliance. Where necessary this may involve a reassessment of limits, or the acceptance of a negotiated access. Suitable clauses are included in Ausgrid's connection agreements to ensure compliance with the supply quality allocation limit via agreed levels of monitoring of the installation, and also for appropriate notification and approval of customers' planned major equipment changes, such as new distorting loads or power factor correction. It should be noted that the NER provides scope for Ausgrid to subsequently enforce automatic access standards where network conditions change.

6. Network Demand and Limitations

6.1 Identified system limitations

This section is now part of our web-based portal located at https://dtapr.ausgrid.com.au, and should be viewed in conjunction with the rating and demand forecast data files which are available for download from Ausgrid's website at www.ausgrid.com.au/DTAPR, and as outlined in Appendix B.

DNSPs are required to provide information on anticipated system limitations in this Annual Planning Report (refer NER Schedule 5.8, clause (c)). Under the former licence conditions and planning standards, system limitations could be readily identified as constraints, due to the nature of the deterministic approach. However, with the removal of those standards, Ausgrid has adopted a probabilistic planning methodology, based on the AER suggested approach of assessing risk of EUE against the value of customer reliability (VCR).

In relation to the timing of anticipated system limitations, for the purpose of this Annual Planning Report, the proposed investment date is reported as determined by the cost / benefit analysis as part of the probabilistic planning methodology. Where appropriate, the date is adjusted to consider resourcing and the timing for delivery.

Consideration of remedial action is required when network limitations are identified due to loading, connection of customers, deteriorating condition/performance or reliability. Identified limitations and indicative solutions are listed in the web-based portal, listing the following information:

- Substation – the name of the location, usually a zone or subtransmission substation;
- Feeder – the name of the feeder, indicating the location of the feeder;
- Timing – the identified need date by which a solution is planned to be implemented; and
- System limitation – an identified network need.

6.2 Dual function assets

6.2.1 Changes in dual function asset status

The list of Ausgrid's dual function assets is reviewed periodically and is used as input for preparing Ausgrid's regulatory reporting, regulatory submission and pricing methodology. For the purpose of the regulatory submission, the list of dual function assets is determined based on the forecast load and the system configuration as at the beginning of the regulatory period.

Ausgrid's dual function network is defined as those assets with a voltage 66kV and above that are owned by Ausgrid and operate in parallel with and provide material support to the Transgrid transmission network.

These assets may either operate in parallel with the transmission network during normal system conditions, or can be configured so that they operate in parallel during specific system conditions.

An asset is deemed to provide material support to the Transgrid transmission network if:

- there is otherwise limited or no system redundancy within Transgrid's network, or
- investment in the transmission system would be required within the regulatory period if that network asset did not exist, or
- the feeder provides operational support to the transmission network (e.g. to facilitate maintenance of transmission assets or improve security of supply) and the asset provides an effective parallel with the transmission network via a relatively low impedance path.

There have been no changes in dual function asset status since the publication of the December 2022 DTAPR.

6.2.2 Dual function connection points

The NER requires a TNSP to set out planning proposals for dual function connection points.

Ausgrid's joint planning with customers, Transgrid and other NSPs may involve the establishment of new connection points. These augmentations are driven by constraints on the distribution network. However, when the augmentation options are considered in the future, the preferred solution may comprise a mix of dual function and distribution network augmentations.

Planning of new or augmented connections involves consultation between Ausgrid and the connecting party, the determination of technical requirements, and the completion of connection agreements. New connections can result from joint planning with Transgrid, other DNSPs, or be initiated by generators or customers through the application to connect process.

Completed new dual function connection points

Refer to Section 2.5 of this report.

Proposed augmentation of existing dual function connection points

Ausgrid has identified the need to install a third 132/33kV transformer at Macquarie 132/33kV STS due to load growth. Refer to Section 2.2 of this report.

Committed new dual function connection points

There are no committed projects for dual function connection points since the publication of the December 2022 DTAPR.

6.2.3 Inter-network impact

The Augmentation proposals described in this report are reliability projects and do not have a detrimental material inter-network impact.

6.3 Ausgrid system total maximum demand forecasts

The forecast system total summer maximum demand and the system total winter maximum demand is shown below. Each chart displays the actual and weather corrected actual maximum demand to 2021/22 and the 50% Probability of Exceedance (PoE) forecast maximum demand Step Change scenario from 2022/23 in megawatts (MW).

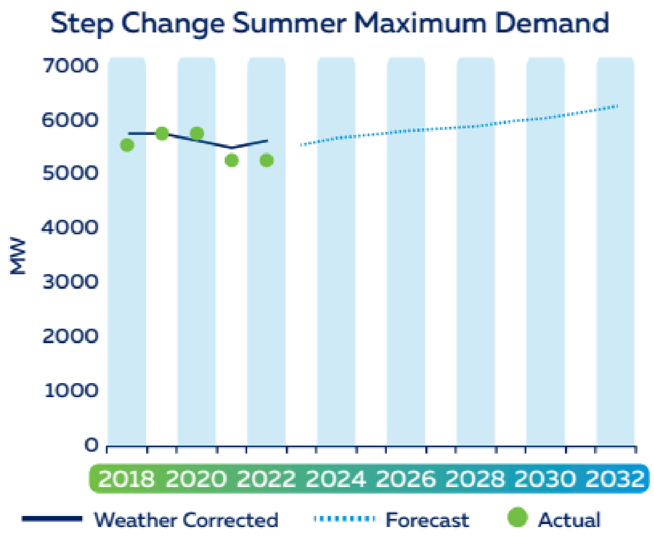


Figure 6-1: Summer Global Peak Forecast

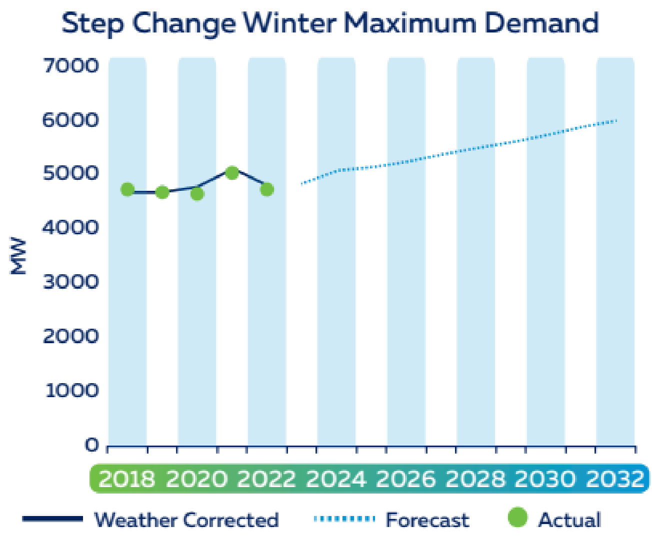


Figure 6-2: Winter Global Peak Forecast

6.4 Frequency control and load shedding

Emergency control schemes exist to make decisions in different situations so as to prevent the system from experiencing undesired conditions, and in particular to avoid large catastrophic disturbances. As a transmission network service provider, Ausgrid has implemented various control schemes for maintaining system security. Some emergency control schemes that have been implemented or proposed to be implemented are described as below.

- Network switching and splitting to prevent circuits tripping due to thermal overloading as a preventive measure to ensure frequency control within limits;
- Under frequency load shedding schemes have been implemented at most zone and subtransmission substations. They will be implemented on existing substations when an opportunity arises during augmentation or replacement works. In response to increasing photovoltaic penetration, not only will new schemes be enhanced with a blocking scheme on the reverse power flow, but existing schemes are also being considered for retrofit at sites already experiencing or close to experiencing reverse power flow. This improvement has been incorporated into the planning process and implemented where possible; and
- Joint planning between Ausgrid and Transgrid to identify and implement load shedding schemes as per the connection agreement.

6.5 Stability

As per NER S5.1.8, the network service provider must plan and operate their network to support stable operation of the national grid in terms of the three criteria below. Ausgrid cooperates with Transgrid to ensure that the power system remains stable as part of the joint planning process.

- The power system will remain in synchronism.

  No generators or major augmentations were commissioned during this period that will affect the power system synchronism.

- Damping of power system oscillations will be adequate.

  No generators or major augmentations were commissioned during this period that will affect the damping of power system oscillations.

- Voltage stability criteria will be satisfied.

  It is important to maintain voltage stability by keeping voltage within acceptable levels during normal operating conditions as well as following the loss of a single network element in the power system. Ausgrid performs QV analysis regularly to ensure that there is adequate reactive margin at each 132kV bus in Ausgrid's network. The criterion is to look at the margin expressed in MVAr to be less than the one present of the maximum fault level (in MVA) at the connection point. As necessary, Ausgrid considers providing reactive support by way of installing shunt reactors and capacitors at suitable locations in the Ausgrid network. The current QV analysis has indicated that reactive margin is sufficient for all the buses in Ausgrid network.

6.6 Primary distribution feeder limitations

6.6.1 Maximum demand and load growth

There are six (6) primary distribution feeders that have either exceeded 100% of their normal cyclic rating in the last year, or are forecast to exceed 100% of their normal cyclic rating over the next two years during normal conditions (N-state). In addition there are twenty-one (21) primary distribution feeders that have either exceeded their rating in the last year, or are forecast to exceed their rating over the next two years during during contingency conditions (N-1 state). Projects have been issued to resolve fourteen (14) of these identified issues, and the remaining are under invetigation. These are outlined in the 11kV Primary Distribution Feeder Capacity data file which is available for download from Ausgrid's website at www.ausgrid.com.au/DTAPR.

Distribution feeders are proactively planned to remain within their ratings by performing regular assessment of the existing and proposed feeder network. Planning includes annual assessment of network performance; more detailed strategic area studies (for areas with a high level of activity and multiple interrelated risks); and localised assessments, generally triggered by requests for HV connections. Where risk is identified, options for network rearrangement, demand management and augmentation are considered to identify the most economic option to address the risk.

Ausgrid has recently developed a 'load-at-risk' assessment tool that is able to systematically test contingency (N-1) scenarios to determine the post-contingency utilisation of each HV and the load reduction required to maintain the network within ratings in each case. For our radial network (the majority of our HV network), this tool has reduced the time to conduct contingency assessments of an area from several weeks to a few hours, depending on the complexity and interconnectedness of the feeders in each area.

6.6.2 Provision of distribution services for embedded generating units

There are no (0) limitations, current or forecast, identified on HV primary distribution feeders related to the provision of services for embedded generation. At this stage, the limitations associated with provision of embedded genarations services on Ausgrid's network are predominately occuring on the LV network.

To identify limitations, Ausgrid determined the existing and forecast growth in demand for embedded generating services by customer segment, and then modelled the demand for services at a customer level during peak and minimum load conditions to identify limitations.

These simulations are computationally intensive as they rely on substantial (often incomplete) data sets that incorporate both HV and LV networks. It takes a number of weeks to collate the data and build each model. A typical network model for an area requires over 5 gigabytes of data and each simulation takes several hours to solve. We are continuing to develop our tools and methodologies for hosting capacity assessments.

7. Planning Coordination

Joint Planning is carried out with other Network Service Providers, in particular Transgrid, Endeavour Energy and Essential Energy.

Three-way joint planning exists between EnergyCo, Transgrid and Ausgrid. It was established to jointly develop the NSW Electricity Infrastructure Roadmap in the HCC REZ.

7.1 Process & Methodology

7.1.1 Transgrid

Ausgrid plans its transmission network jointly with Transgrid as the Ausgrid 132kV dual function network provides support to Transgrid's 330kV network. In carrying out joint planning Transgrid and Ausgrid:

- meet regularly, at least 4 times per year;
- record minutes and decisions;
- prepare work plans and monitor progress;
- assess augmentation options on the basis of least cost to the community;
- initiate projects within each organisation following the normal approval processes; and
- jointly consider demand management as an option.

Ausgrid and Transgrid have established a Joint Planning Committee structure which comprises a steering committee and a joint planning sub-committee to coordinate the planning activities of Ausgrid and Transgrid in accordance with the joint planning requirements of the National Electricity Rules. Under the agreed terms of reference, there are quarterly meetings of the sub-committee and bi-annual steering committee meetings. Members include relevant planning, operations, design and project development staff. The key considerations of the joint planning committees are specified in the joint planning charter. Committee activities and deliverables are managed through an agreed work plan, with decisions documented in approved Joint Planning Reports for major milestones.

From 1 July 2018, Transgrid and Ausgrid are required to comply with the "NSW Electricity Transmission Reliability and Performance Standard 2017". This standard requires the NSW electricity transmission network to be designed and planned to a certain level of redundancy and level of EUE. This is a significant change from the former deterministic assessment of the network.

7.1.2 Transgrid & EnergyCo

Through its involvement in the three-way joint planning framework with EnergyCo and Transgrid, Ausgrid is seeking to develop network options which establish of 1GW transfer capacity in the Hunter and Central Coast Renewable Energy Zone. This development includes identification of scope and investment details as well as technical requirements.

7.1.3 Other DNSPs

Ausgrid follows the same principles when joint planning with Endeavour Energy and Essential Energy. However due to the limited number of network dependencies between the organisations, joint planning meetings may only take place once per year, or less, unless a particular issue has been identified and needs to be progressed and monitored.

Joint planning meetings may be initiated by any party to discuss planning issues, identified network needs and proposed solutions near adjoining network boundaries that are likely to affect either party. The joint planning meetings are also the forum used to discuss proposed changes on the network that may have a material impact on either DNSPs network.

7.2 Joint Planning Completed in 2023

7.2.1 Transgrid

Sydney Inner Metropolitan Transmission Load Area

Existing and future constraints on the Sydney Inner Metropolitan transmission network are centred on two critical areas:

- Transmission supply into Beaconsfield BSP from Bulk Supply Points at the edge of the city, Sydney South, Sydney North, and Rookwood Rd BSP. This is known as Transmission Corridor 1 ('TC1').
- Transmission supply into Haymarket BSP and surrounding Ausgrid 132kV zone substations from Sydney South BSP (Cable 42) and Ausgrid 132kV connections from Beaconsfield BSP and the meshed 132kV network. This is known as Transmission Corridor 2 ('TC2').

Both transmission corridors operate as meshed systems of 330kV and 132kV circuits, with significant interdependencies between both corridors. Both have limitations due to the age and condition of existing circuits, including significant reduction in capacity of cables where in-situ conditions are not adequate to support design ratings. The Inner Metropolitan Area Joint Planning strategy must resolve issues on both corridors.

After extensive consultation from 2014 through the RIT-T, Transgrid's 2018-2023 regulatory submission and numerous other forums, Transgrid began construction in 2020 on the first stage of the preferred strategy for Powering Sydney's Future. This strategy consists of:

- A combination of non-network solutions to manage the risk of unserved energy before the network option can be commissioned;
- installing two 330kV cables in two stages, with commissioning of the first cable in time for the 2022/23 summer;
- operating 330kV Cable 41 at 132kV from 2022/23; and
- decommissioning Ausgrid's cables in two stages.

Commissioning of the first stage was completed in June 2022. This includes the first 330kV cable and operating 330kV cable 41 at 132kV. Decommissioning of the first stage of Ausgrid's cables was completed in 2023.

Other Transmission Load Areas

Transgrid's Sydney East 330/132kV BSP was commissioned in 1974. The substation is a major interconnection point in the Transgrid 330kV network and is the sole source of supply to Ausgrid's substations in Sydney's Northern Beaches and North Shore areas. One of the 330/132kV transformers at Sydney East Substation was recently replaced but the remaining three transformers are now approaching the end of their serviceable life.

Joint planning in 2018 determined that two of the three older Sydney East transformers should be replaced and the third should be retired without replacement. Transgrid completed the RIT-T process to replace these two transformers in June 2019. Transgrid and Ausgrid will review the need for a fourth transformer at Sydney East as part of the normal annual planning process. Work to replace the two transformers was completed in 2023.

In addition, a condition assessment of Sydney East BSP identified that the Secondary Systems require replacement, requiring Ausgrid to carry out works on our end of the impacted feeders. On TransGrid's request, Ausgrid is facilitating the required protection replacement works on all affected Ausgrid feeders. Protection upgrades are expected to coincide with Transgrid's program of works at Sydney East BSP which are scheduled for completion by 2027/28.

To manage system fault level increase at Transgrid's Newcastle 330/132kV Bulk Supply Point substation resulting from the connection of Hunter Power Station, minor upgrades will be performed on the 132kV busbar. The resulting fault rating will be 43.8kA for fault currents flowing in phase conductors and 43kA for fault currents flowing into ground.

Additionally, Ausgrid shall reconfigure the 132kV network at Merewether STS to remove the network parallel between Newcastle and Waratah West 330/132kV Bulk Supply Points.

Voltage Planning

Transgrid and Ausgrid initiated a voltage specific joint planning stream in 2020. The voltage specific planning stream provides for a BSP to LV customer planning approach for our whole network whilst aligning with the upstream Transgrid voltage requirements. This has provided efficient solutions in improving voltage issues and DER hosting capacity. This work has continued in 2023.

Embedded Generation Planning

A number of large embedded generator and Battery Energy Storage System connections to the Ausgrid network has and will require joint planning and assessment with Transgrid.

- Muswellbrook 150MW BESS. Connection application has been submitted to Ausgrid and Network Impact Assessment studies have been completed. Due diligence studies are ongoing in consultation with AEMO.

- Muswellbrook Coal 135MW Solar Farm. Connection application has been submitted to Ausgrid and Network Impact Assessment studies have been completed. Ausgrid due diligence studies are completed and consultation is nearing completion with AEMO. Additionally, wide area impact assessments are being performed to determine if Muswellbrook Coal 135MW Solar Farm will exacerbate oscillation issues in the Transgrid Northern region.

7.2.2 Endeavour Energy

No network issues were identified that affect either Endeavour Energy or Ausgrid.

7.2.3 Essential Energy

A joint planning meeting with Essential Energy will be held in October this year. The focus will be to discuss ownership of assets near network boundaries and identify assets that are out of area and report them to IPART appropriately.

Increasing levels of solar penetration within both networks will need to be monitored, including the emergence of Battery Energy Storage Systems to be connected within Ausgrid's network over the next 12months (at Brandy Hill Zone Substation) that also supply Essential Energy customers.

7.3 Planned Joint Network Investments

7.3.1 Transgrid

Planned future network investments, excluding committed projects, discussed at Transgrid - Ausgrid joint planning meetings in the preceding year include:

- The shunt reactor at Sydney East BSP has been identified for replacement due to asset condition issues. It is essential to manage the voltage and power factor at Sydney East BSP

- The Ausgrid network is experiencing high voltages and leading power factor for an increasing proportion of the year. One of the potential solutions may require installation of a new shunt reactor at Beaconsfield BSP. Investigations will continue in 2024.

7.3.2 Endeavour Energy

There is currently a project to supply Ausgrid's Auburn and Lidcombe zone substations from Endeavour Energy's Camellia Transmission Substation.

7.3.3 Essential Energy

A project to rectify the 33kV supply to Essential Energy from Ausgrid's Tanilba Bay zone substation to meet the capacity requirements specified in the connection agreement was completed in 2023.

7.4 Additional Information

Further information on Transgrid and Ausgrid's completed joint planning and joint network investment can be found in Transgrid's Transmission Annual Planning Report. It is published on their website as well as AEMO's website. Further information on completed Ausgrid and other DNSP joint planning and joint network investments may be found in other section of this report.

Where a proposed future project satisfies the requirements for a RIT-T or RIT-D project, the identification of non-network options, the consultation on potential credible options and their economic assessment will be published in accordance with the NER.

8. Information and Communications Technology Systems Investments

8.1 Information and Communications Technology

Information and Communication Technology (ICT) provides the critical business systems to enable Ausgrid to perform its network operations, which includes undertaking effective asset management planning, and fulfilling regulatory and statutory reporting obligations.

ICT systems are integral to performing functions such as asset lifecycle management, asset operations, customer and market management and financial reporting, with Supervisory Control and Data Acquisition & Network control systems being integral to performing key network activities such as monitoring and managing the electrical network.

Information technology also allows Ausgrid to prudently adopt and effectively implement technology that enables Ausgrid to deliver better services to network customers and reduce costs over time.

Key ICT systems support the following Ausgrid core business functions:

Domain	Description
Asset Lifecycle Management	Asset management is one of Ausgrid's most critical functions. The asset management business function concerns the management of all physical components of Ausgrid's electrical system across the lifecycle of assets from investment through to retirement/replacement at the component level. It is also tightly integrated with operations and planning at the Network level. The asset management systems are therefore integral to providing services, reliability and quality of supply and protecting the safety of customers, community and employees.
Works Management	Works management refers to the efficient management of Ausgrid's resources in the delivery of services within the Network. It encompasses processes which are tightly associated with the asset management capability described above, scheduling and dispatch, warehousing and mobility.
Market Management and Customer Management	Market management includes all of the processes related to the collection of revenue resulting from the provision of energy distribution services. The main processes in delivering this business capability are metering, revenue management, and network billing. Market management also incorporates network pricing, market transactions, meter data management and financial reporting. Customer management includes functions and processes related to customer interactions, connections and disconnections, as well as the provision of a customer contact centre.
Enterprise Management	Commercial and corporate includes functions necessary for executive control and oversight of normal organisational functions, such as finance, reporting, strategy development and implementation, human resource management, non-system asset management and property management.
IT Management	The effective management of information across Ausgrid has become crucial. The nature of the business dictates that information needs to be collected, managed and analysed in order to provide timely and effective decision support. Information management is also required to satisfy regulatory obligations and core financial and organisational reporting and analysis. Infrastructure provides the backbone to Ausgrid's business capabilities and systems. It includes all of the hardware, communication, operating systems and devices required to support the business.
Asset Operations	System IT provides the core functions regarding provision and development of the Advanced Distribution Network Management System (ADMS) and Supervisory Control and Data Acquisition (SCADA) systems, core telecommunication networks (MPLS, 4G) and distribution network monitoring and control.

8.1.1 ICT investment actual 2023/24 and forecast

Throughout the year, key applications and infrastructure have been maintained to enable a reliable, scalable and secure computing platform. These include our SAP applications, enterprise content management platform, customer relationship management platform, supporting Ausgrid critical infrastructure licence conditions, metering systems and data centre and telecommunications technologies. Ausgrid has also commenced the migration of applications from data centres to the cloud.

In the development of the forward plan and strategy the following principles were adopted:

- **Customer Centric:** Knowing our customer to enable us to provide a seamless and efficient service;
- **User Experience:** Enable a secure, capable and reliably mobile experience;
- **Data Driven Culture:** Extract value from data and enhance capabilities; enable self-service analytics capability;
- **Platforms:** Enable business agility with flexible "pay as you go" models; continue the focus on efficiency by Consolidating, Standardising and Automating;
- **Cyber Security:** To protect the network and customer information including compliance with laws and the distributor licence conditions, and to be recognised as the leader in cyber security within the Power and Utilities industry.

The table below contains a summary of actual ICT investment in 2021/22 and forecast investment in 2022/23 through to 2026/27.

ICT Investment actual 2021/22 and forecast 2022/23 to 2026/27 (Nominal $) *						
	Actual ($m)	Forecast ($m)				
	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Total ICT Capital Investment	55.2	103.4	67.0	135.4	185.0	117.2

*Excludes the Advanced Distribution Management System – see below.

8.2 Advanced Distribution Management System (ADMS)

Ausgrid's distribution network is managed using a group of systems where control room staff integrate various information flows and take consequent actions to manage the network, this includes maintaining the security and stability of the network. The ADMS is the core operational management tool in that group of systems, providing an integrated set of tools to remotely monitor and control the network, manage system outages, improve planned and emergency event management, and optimise fault location and restoration processes.

The core ADMS monitoring and control functionality was implemented in November 2022 and the remaining functionality of the ADMS system will be implemented over the next few years, further replacing existing legacy technologies. Once complete, this will enable the continued expansion of features to better manage distributed energy resources in conjunction with a Distributed Energy Resource Management System (DERMS) and enabling advanced features such as Fault Location Isolation and Rectification (FLISR) and integration of Advanced Metering Infrastructure (AMI).

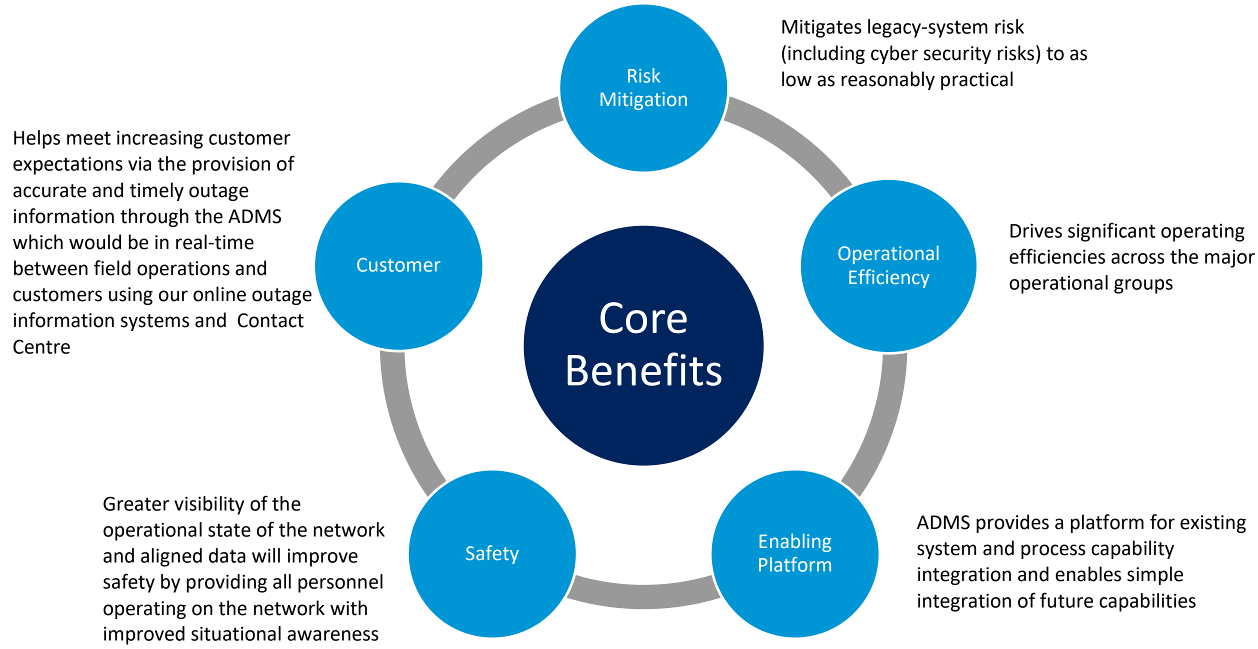
This will allow Ausgrid to provide the services expected by customers and stakeholders in the rapidly changing energy market.

8.2.1 ADMS benefits

A mature ADMS will deliver benefits to customers with the following improvements to current functionality:

- management of system outages and restoration works;
- planned and emergency event management;
- situational awareness from power-flow analysis;
- network fault location analysis, automated isolation and restoration capabilities;
- provision of a platform for the integration of distributed energy resource management systems as well as other corporate systems enabling the Distribution System Operator (DSO) construct;
- an ability to better integrate with Ausgrid's enterprise systems to ensure a consistent real time situational view (that is not dependant on staff entering and updating information in multiple systems); and
- the ability to use digitised switching instructions which would enable non-verbal communications between the control room and field operators.

The core benefits assessed in the business case for the ADMS implementation are described in the following diagram.

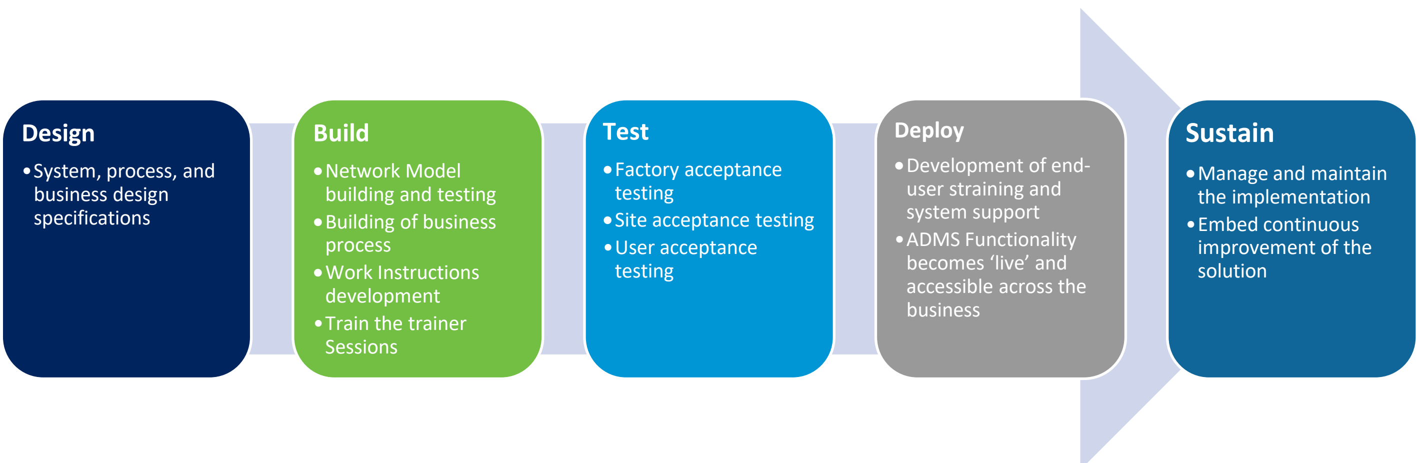


8.2.2 ADMS Program implementation

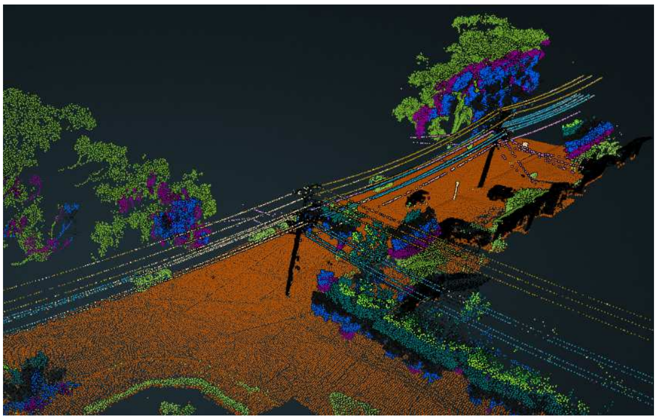
The overall program is delivered via a phased approach which has been adopted to mitigate the risks of a large technology rollout and to allow the business time to adapt to the ADMS functionality across three phases, each building upon new capability acquired in the prior phase.

Phase	Description	Timing
1	Replacement of legacy distribution management system - this delivers mission-critical monitoring and control functionality (SCADA) – Practically complete	2019 – 2022
2	Modernisation of operations for planned and unplanned work, deployment of additional distribution management applications and establishment of a Low Voltage Network model	2019 – 2024
3	Implementation of Advanced Applications – this delivers Automated Fault Detection and Isolation Restoration and advanced applications to enhance the optimisation of the network, e.g. Distribution Energy Resource Management	2022 - 2025

Each Phase will follow a sequence of 5 stages as outlined below:



8.3 Network Asset Digitisation



The implementation of the Network Digitisation Program is delivering a digital twin of Ausgrid's overhead network that will enable a range of cost efficiencies within network planning, design and works delivery. It is focused on four fundamental streams to acquire accurate network asset data, integrate various information sources and model in a virtual world that is accessible to staff and relevant third parties to better inform business decisions and drive efficiencies. These streams are:

Data acquisition	Acquisition of new asset data such as Light Detection and Ranging (LiDAR) point clouds and photography, and other remote sensing sources, in order to develop the spatial representations of the network.
Data management	Development of systems and tools to integrate asset information between systems and support data acquisition processes.
Digital twin	Establishment and development of the core digital twin system and associated capabilities to leverage Ausgrid's asset information and develop the virtual 3D world from which asset information can be processed, analysed and accessed.
Analytics and insights	Development of the analytical capabilities and reporting that enables asset insights to be derived from the digital twin.

8.3.1 Network asset digitisation benefits

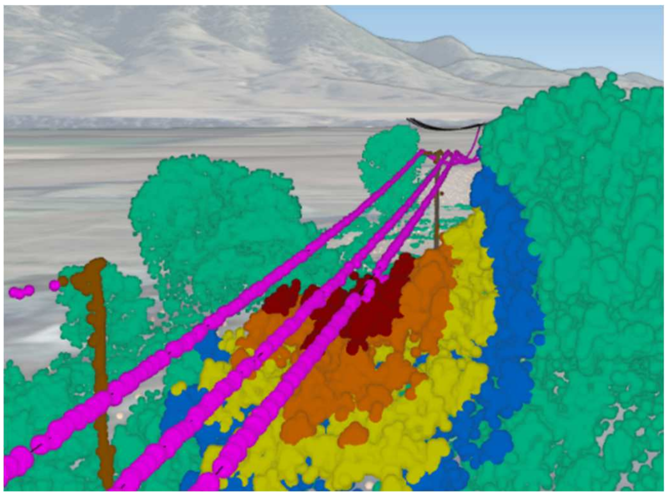
Ausgrid manages a substantial set of asset information to enable efficient and effective business operations. Asset information is recorded and processed into asset management systems from:

- over 5 million recorded assets;
- over five hundred thousand inspections/site visits annually; and
- hundreds of measurements per day from nearly a million network points.

Information from these assets and inspections is currently collected through both automated and manual processes. However, recent advances in technology such as Light Detection and Ranging (LiDAR), panoramic imagery and processing, 3D modelling, machine learning algorithms and capture techniques are allowing utilities to develop much more comprehensive and accurate data sets at significantly reduced costs.

The benefits of implementation of the Network Digitisation program include:

- Improving capital efficiency from reduced planning and design effort for overhead line investigation and replacement activities;
- Improved network reliability and reducing network risk (outage, fire-starts, emergency response) from identification and prioritisation of defects and the installation of LV spreaders where advantageous in non-bushfire areas;
- Reduced capital and operational expenditure associated with vegetation encroachments;
- Reduced operational expenditure by optimising vegetation management cycles; and
- Information partnering with other utilities and local councils.



8.3.2 Network Digitisation Program implementation

Ausgrid has continued to acquire LiDAR and imagery technology to capture Ausgrid's overhead assets and develop at scale our digital twin. We are currently in Stage 2 of our long-term roadmap for development of the digital twin, as described below.

This approach will provide for review and validation of ongoing benefit realisation prior to the implementation of subsequent stages. Each data acquisition and analysis cycle will be delivered in a staged approach allowing also for the adaption of new technologies as they become viable.

Stage 1 FY21 - FY22

- Initial network asset acquisition, data management and platform development

Stage 2 FY23 - FY24

- Second cycle of asset acquisition, processing and comparative analytics; and

Stage 3 FY25+

- Ongoing asset acquisition and data maintenance.

The estimated program costs are provided in the table below.

Program cost estimates including contingency & overhead ($m, nominal)					
	FY21	FY22	FY23	FY24	FY25
Network Digitisation	2.3	3.0	4.8	4.5	3.8

Appendix A: How We Plan the Network

A.1 Ausgrid and the DTAPR

A.1.1 Distribution Network

The National Electricity Rules (Version 200) require that the annual planning review includes the planning for all assets and activities carried out by Ausgrid that would materially affect the performance of its network. This includes planning activities associated with replacement and refurbishment of assets and negotiated services. The objective of the distribution annual planning review is to identify possible future issues over a minimum five-year planning horizon that could negatively affect the performance of the distribution network to enable DNSPs to plan for and adequately address such issues in a sufficient timeframe.

This document provides information to Registered Participants and interested parties on the nature and location of emerging constraints on Ausgrid’s subtransmission and 11kV distribution network assets, commonly referred to as the distribution network. The timely identification and publication of emerging network constraints allows the market to identify potential non-network options and Ausgrid to develop and implement appropriate and timely solutions.

A.1.2 Transmission Network

The NER require network service providers, who own and operate dual function assets to register as Transmission Network Service Providers by virtue of the definition of 'TNSP' in the rules. Certain parts of the rules treat dual function assets in the same way as other subtransmission assets. However, for the purposes of the transmission annual planning review and reporting, dual function assets are treated as transmission assets requiring a Transmission Annual Planning Report. For the purposes of economic evaluation and consultation with Registered Participants and Interested Parties, dual function assets are treated as distribution network assets and are subject to the same economic evaluation test.

Ausgrid’s dual function network is defined as those assets with a voltage of 66kV and above that are owned by Ausgrid, and operate in parallel with and provide material support to the Transgrid transmission network. These assets may either operate in parallel with the transmission network during normal system conditions or can be configured so that they operate in parallel during specific system conditions.[12]

An asset is deemed to provide material support to Transgrid’s transmission network if:

- there is otherwise limited or no system redundancy within the transmission network, or
- investment in the transmission system would be required within the regulatory period if that network asset did not exist, or
- the feeder provides operational support to the transmission network (e.g. to facilitate maintenance of transmission assets or improve security of supply) and the asset provides an effective parallel with the transmission network via a relatively low impedance path.

Ausgrid reviews the function of its dual function assets periodically to determine if they continue to provide material support to Transgrid’s transmission network. This review is used as input for preparing Ausgrid’s regulatory reporting, the regulatory submission, and pricing methodology. For the purpose of AER Revenue Determination submissions, the list of dual function assets is determined based on the forecast load and the system configuration as at the beginning of the regulatory period.

[12] Network Planning Standard NIS433: Classification of Dual-Function Assets

A.2 Ausgrid's Planning Approach

The network planning and development process for both the distribution and transmission networks is carried out in accordance with the NER Chapter 5, Part D, Network Planning and Expansion. Planning for distribution and subtransmission assets is carried out in accordance with NER 5.13.1 - Distribution annual planning review and NER 5.12.1 - Transmission annual planning review for dual function assets.

A.2.1 Investment Objectives and Decision Criteria

Ausgrid's investment objectives are set to comply with the National Electricity Rules (**NER's**) and the NSW Licence conditions for a DNSP, to ensure the safety of the people and improve the efficiency of the business

The following table, taken from Ausgrid's Asset Management Strategy, provides a summary of Asset Management objectives:

Enhancing Safety	Protecting people from harm so far as is reasonably practicable.
Improving Network Performance	Improving the reliability, security and resilience of supply to create a better customer experience.
Delivering Affordability	Delivering customer affordability through efficient optimisation of whole of life costs and improved operational performance.
Increasing Sustainability	Transforming the network through reducing emissions and providing choice and control for customers to more easily access sustainable energy.
Making a commercial return	Provide dividend certainty through effective and optimised investment that responds to incentives.

These investment objectives are supported by the development and delivery of investments which efficiently achieve the key network performance outcomes outlined below:

Network Performance Outcomes

Customer Connection	Connect customers to the network so that they can receive electricity supply, or supply energy to others.	**Resilience & Reliability**	Deliver network performance (resilience and reliability) that is equitable across customers and only to a level that customers are prepared to pay for.
Capacity	Deliver a system that can supply forecast customer demand for and supply of electricity.	**Fault Level**	Fault currents which are within a range which allows network and customer equipment to operate correctly and safely.
Voltage	Maintain the operating voltage within specified limits to support customer behind the meter activities including DER.	**Power Quality**	Provide supply that allows customers to successfully operate their equipment in the same network as others
System Stability	Facilitate the stable operation of the national electricity market (NEM)		

Network Planning Process

Ausgrid follows a structured planning process that can be summarised by the following diagram from our Network Investment Policy. The planning phase involves identifying the investment needs and risks based on the probability and consequence of adverse events; developing one or more options to address these needs; assessing costs and benefits associated with those options under various scenarios to select the preferred option and initiating the preferred option.

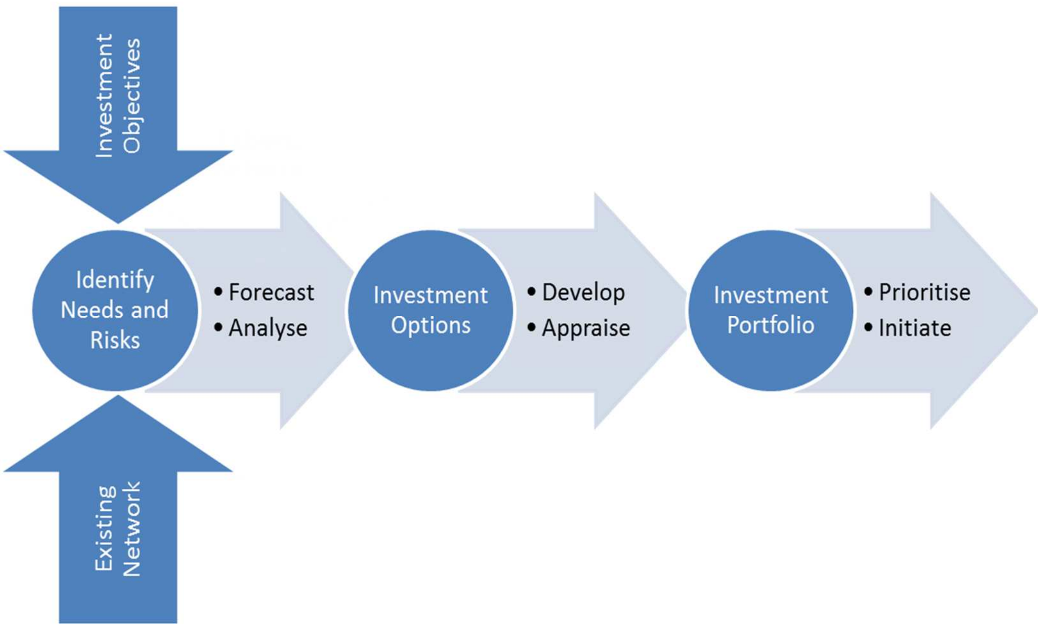
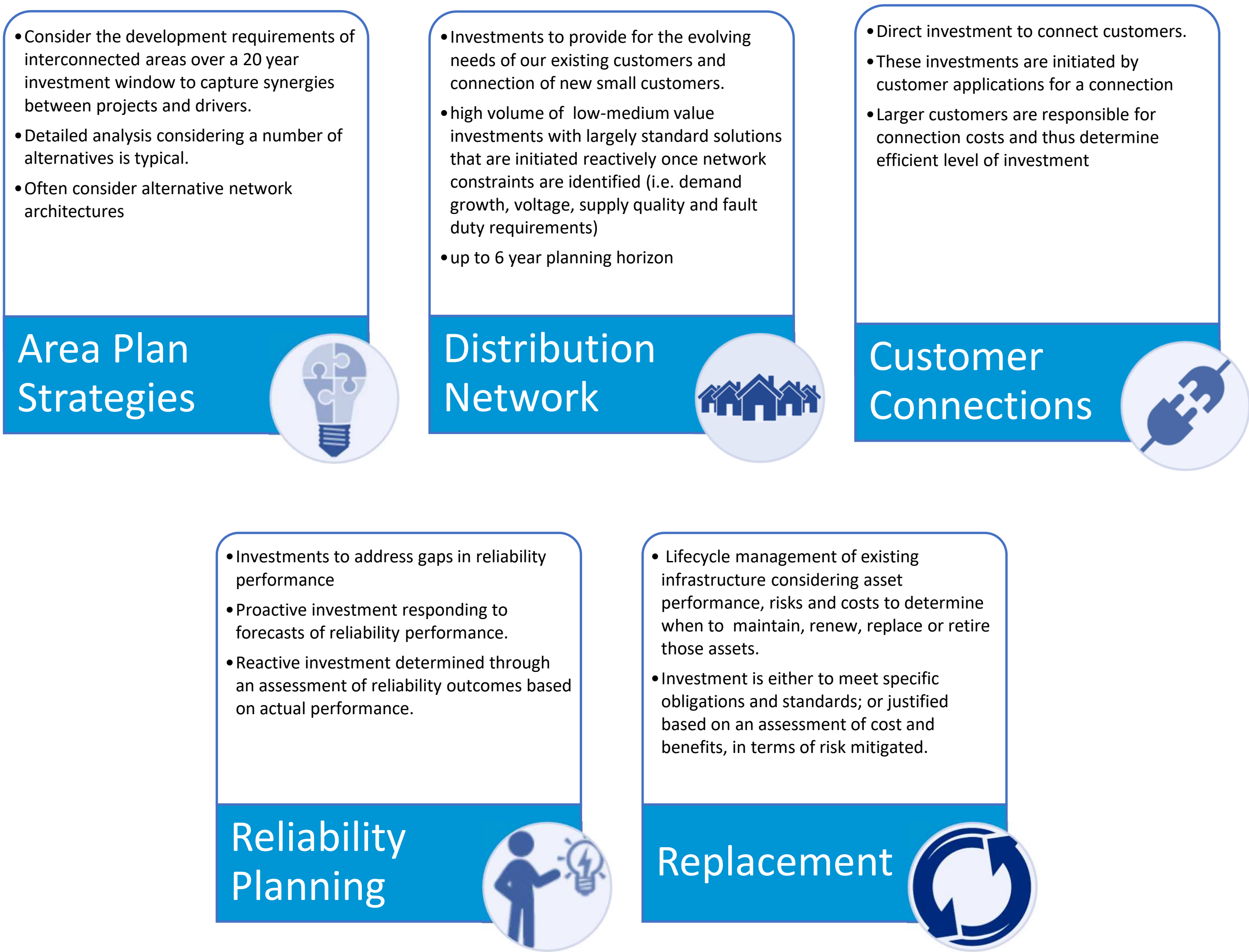


Figure A-1: Ausgrid planning process

The timeframe and complexity of this process varies according to network level, risk profile, and the project scale and intent. Accordingly, Ausgrid organises its planning activities by distinct investment categories. This approach allows Ausgrid to adopt a level of analysis and justification that is commensurate with the costs, risks and obligations associated with each investment category discussed below:



The following tools have been implemented to assist Ausgrid in making prudent, cost-effective investment decisions:

1. Governance Framework

The Governance Framework provides guidance and accountability for the planning, development, endorsement, and approval of network investments. It defines how Ausgrid plans and invests in its network.

The governance framework is comprised by the following stages

I. **Policies and standards** are used to define the technical requirements for any future changes to the network and therefore drive the nature and size of network investments.

II. **Long-term plans and strategies** provide a long term view of the network and outline a 5-10 year program of works required to meet known asset performance requirements, new large connections, infrastructure standard compliance gaps and likely capacity constraints. Sub-transmission area plans are used to identify needs/constraints up to 20 years in advance and allow investment decisions to be made in the short term to enable the lowest cost solutions to be delivered over the long term.

III. A resource strategy is developed in the form of **program delivery models**. They consider resource requirements by work program or job type, current utilisation rates and productivity targets.

IV. The integration of these guidelines makes possible the development of a **Portfolio Investment Plan (PIP)**, which is updated on annual basis and approved via a Gate process. At **Gate 1**, investments are reviewed and approved by Ausgrid's Board at the portfolio level. Once approved, the PIP becomes the baseline for the annual budget/Management Business Plan (MBP) and for the regulatory proposal (in years when a proposal is submitted to the AER).

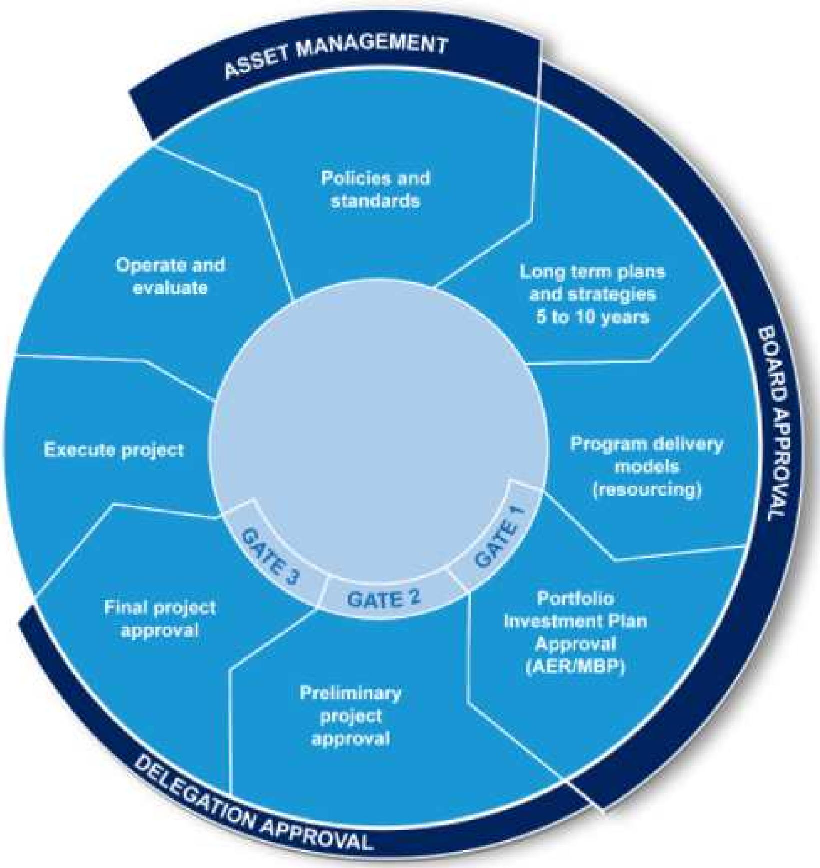
V. At **Gate 2**, **preliminary approval** is provided for investments at the project and program level. The focus is placed on assessing the network need for the program/project, prior to proceeding to the detailed estimate stage. Preliminary funds can be authorised to enable completion of design work, place orders for long lead time standard equipment and seek market consultation for externally delivered works.

VI. At **Gate 3**, **final approval** is provided for investments. The governance focuses on testing the efficiency of the delivery model and confirming the project/program timing, risk and cash flows. Investment approvals are obtained in accordance with applicable delegations and sub delegations of authority.

VII. After that, **project and program execution** can be initiated. Delivery is monitored for each individual project or program and milestones are reviewed on monthly basis. Variations can be raised if delivery and risk outcomes cannot be achieved within existing approval limits.

VIII. Once investments are completed, the resulting assets are commissioned and ready to **operate**. Projects must have a formal close-out. Post-implementation reviews are required to **evaluate** performance and provide feedback/lessons learnt for similar investments in the future.

These stages are illustrated in the diagram below, representing the governance lifecycle:



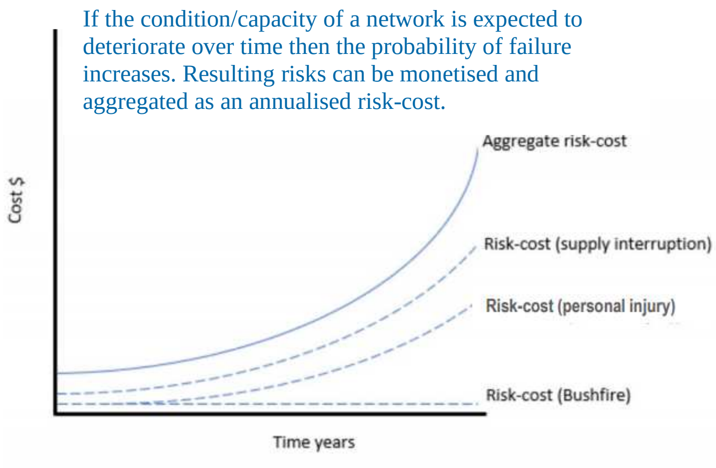
2. Cost Benefit Analysis (CBA) / Options Analysis

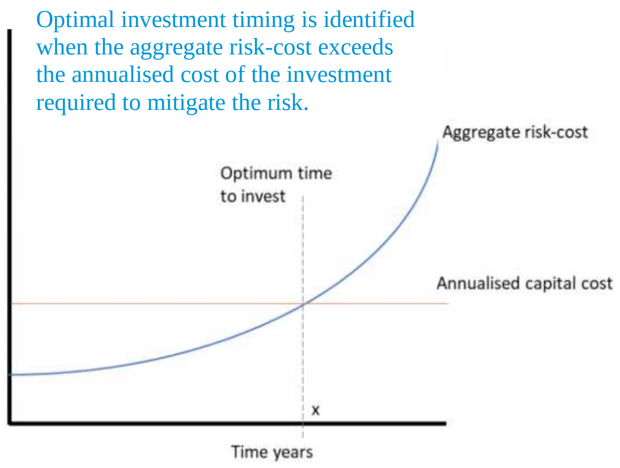
CBA is an investment decision support tool that measures the benefits of an action minus the costs of taking that action. It typically involves tangible 'cash' metrics such as capex invested or operational costs saved as a result of the decision to pursue a project, and often includes intangible benefits and costs, such as reduced supply, environmental or safety risks, with a dollar value assigned to the intangible items to make them comparable with the tangible financial components on a common basis.

Capex, ongoing opex, savings in future capex and opex are tangible elements that can usually be estimated with a reasonable degree of accuracy. They are typically modelled as direct cash flows in the CBA.

Loss of supply (i.e. unserved energy), safety and environmental risks are typically unknown and can only be included on a probabilistic basis – i.e. the likelihood of an event in any given future year is multiplied by the monetised risk cost associated with that event occurring. If an investment is implemented to avoid these risks, they will become benefits from a customer perspective and modelled as indirect cash flows in the CBA.

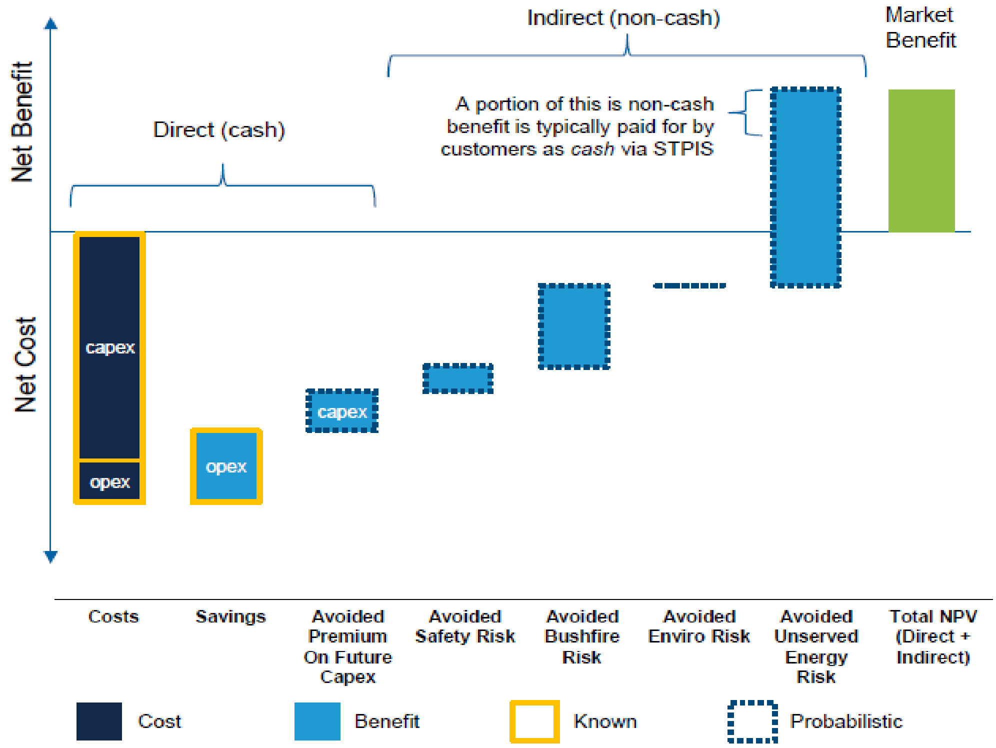
At the point where the annual benefit to society of an investment exceeds the costs customers will incur under the regulatory framework if the investment is made, the investment is considered justified and should proceed.





The AER published guidelines with details on what they expect network businesses to include when using CBA to justify a capital investment.

In most network investments, the costs and benefits span multiple years. Therefore, a present value approach is applied to ensure future benefits can be compared on a like for like basis with expenditure now. Where future costs and benefits are discounted at or above the current regulated cost of capital, the CBA is implicitly comparing the option of making an investment against the opportunity of having the cash available for other purposes.



The CBA needs to identify the option that "maximises the net economic benefit across the Market". As a result, costs and benefits must be assessed in aggregate across all market participants, including those that "consume, generate, and transport electricity".

CBA is useful to assess the relative value of different investment options.

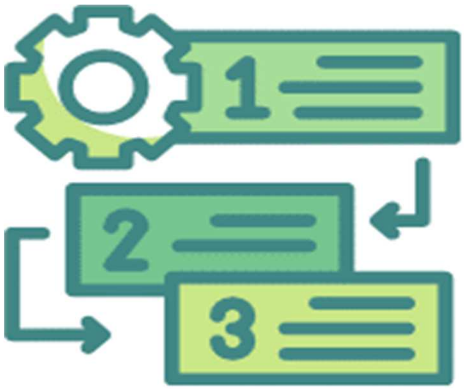
An investment option showing a positive NPV is not enough to justify a decision to go ahead with such investment. It should be assessed against other investment options that could also manage/mitigate the identified risks, to determine which option has the highest NPV.

The investment option with the highest market NPV (i.e. the most favourable to the overall community) should be the preferred option.

3. Capex prioritisation/optimisation

The outcomes of CBA applied to projects and programs (i.e. NPV results, Benefit/Cost ratios) are used as input information to rank and prioritise capital expenditure across the network investment portfolio.

Consideration is also given to the contribution made by projects/programs to support customer outcomes, corporate strategy and network performance targets, along with their ability to mitigate/reduce identified risks (i.e. workplace and public safety, environment, loss of supply, financial, etc) on the network.



A.2.3 Network Area Plans

Area Plans relate to major investments in the network and considers all of Ausgrid's obligations (irrespective of network type, voltage or investment drivers). The majority of investments within the Area Plans are subtransmission investments due to the greater interconnectivity of the network at this level and because these investments are generally complex and high in value.

To ensure Ausgrid’s investment is prudent and efficient, our planning of major investments in the network:

- is based on meeting the requirements of geographic areas, defined on the basis that they represent discrete electrical areas and with relative independence from network interconnections;
- considers Ausgrid’s obligations under the NER and other applicable regulatory instruments in a holistic manner; and
- considers identified needs over a twenty-year planning horizon to allow for the development of a long term strategy that addresses various drivers and minimises long term cost.

Projects that comprise the preferred strategy for each Area Plan are determined by a probabilistic planning approach. This approach assesses cost and benefit, based on the risk of EUE and the VCR, with the preferred strategy entered in the Major Project List (Project List). Each project initiated is based on this list and on the expected project lead times, and in accordance with Ausgrid’s Investment Initiation Standard. The Project List records the identified system limitation and need date, the required completion date and the estimated cost for each project.

The Area Plans are reviewed as significant changes to network needs are identified. In order to optimise project implementations, the timing of major projects is reviewed annually as new information and forecasts become available. Within the area plan cycle, major changes are captured in Area Plan Addendums or Planning Reports. The Project List also forms the basis of the economic assessment, consultation and reporting requirement under the RIT-D.

Appendix B: Demand Forecast

B.1 Data Tables Online

In keeping advice from the AER, that data should be made accessible in a format that can been readily interrogated, forecast and related data tables are published online and can be accessed via Ausgrid's website at www.ausgrid.com.au/DTAPR.

Table definitions for the 'Substation capacity and demand forecast' table and the 'Dual Function asset 10-year demand forecast' table located on Ausgrid's website are as follows:

Substation capacity and demand forecast table definitions

Heading Label	Description
Area Plan	An area as defined by Ausgrid used to describe a collection of substations of similar geographical region
Substation	Name of the substation. Details on the primary and secondary voltages of the substation included in the name to differentiate some locations of similar naming convention
Substation Type	Denotes either Zone Substation (ZS) or Subtransmission Substation (STS)
Total Capacity (MVA)	Maximum load able to be carried by the substation with all elements in service. A summer and winter Total Capacity value is provided
Firm Capacity (MVA)	Load able to be carried by the substation with the largest rated element out of service. A summer and winter Firm Capacity is provided
Load Transfer Capacity (MVA)	Amount of load that can be restored in the event of a whole zone outage by switching the distribution network. The transfer capacity assumes that a single zone is rendered out of service and the rest of the network is in system normal configuration. A summer and winter Transfer Capacity is provided
95% Peak Load Exceeded (hrs/yr)	The number of 15 minute occurrences that exceeded the 95th percentile value of maximum demand was summed and divided by four to determine the "hours within 95% of peak" value. A summer and winter 95% Peak Load exceeded value is provided
Embedded Generation - Solar PV (MW)	The Solar PV capacity by zone substation is consistent with the information used in the forecast and is current as at 31 March 2022 and 31 August 2022 for summer and winter respectively and includes all known systems. The solar generation capacity is based on information gathered from the application for connection forms completed at the time of applying for a solar installation and recorded in the Distributed Energy Resources Register
Embedded Generation - Other (MW)	Embedded generation "Other" includes all known diesel, landfill biogas, coal seam methane, natural gas including tri-generation and co-generation, hydro and mini hydro, coal washery, and waste heat recovery generating units known to Ausgrid. Not all of these units export to the grid as they are not capable of operating in parallel with the Ausgrid network and are intended for standby operation in island mode.
Actual Load (MVA)	Recorded peak demand for the substation. A summer and winter actual is provided. The actual loads are provided for the three years with the most recent year analysed being summer 2021/22 and winter 2022.
Actual Load (PF)	Recorded power factor for the substation at time of peak load. The value is compensated and takes into account the actual switching of capacitors at the substation at time of peak load. A summer and winter actual is provided
Forecast Load (MVA)	POE50 planning forecast peak demand in MVA for each respective forecast year for the substation. A summer and winter forecast is provided with the forecast starting from Summer 2022/23 and winter 2023.
Forecast Load (PF)	Forecasted power factor as calculated from POE50 planning forecast for each respective forecast year for the substation. The value is compensated and takes into account the forecasted switching of capacitors at the substation for any given forecast year. A summer and winter forecast is provided

Dual Function asset 10 year demand forecast table definitions

Heading Label	Description
Substation	Name of the substation. Details on the primary and secondary voltages of the substation included in the name to differentiate some locations of similar naming convention
Substation Type	Denotes either Zone Substation (ZS) or Subtransmission Substation (STS)
Substation Actual MW	Recorded peak demand in MW for the substation. A summer and winter actual is provided
Substation Actual MVAr	Recorded peak reactive load for the substation. The value is compensated and takes into account the actual switching of capacitors at the substation at time of peak load. A summer and winter actual is provided
Substation Forecast MW	POE50 medium scenario planning forecast peak demand in MW for each respective forecast year for the substation. A summer and winter actual is provided
Substation Forecast MVAr	POE50 medium scenario planning forecast peak reactive load in MVAr for each respective forecast year for the substation. The value is compensated and takes into account the forecasted switching of capacitors at the substation for any given forecast year. A summer and winter actual is provided

B.2 Zone and subtransmission load forecasting methodology

This section describes the maximum demand planning forecasting methodology (the forecast) used by Ausgrid for zone substations and subtransmission substations.

The forecasts of peak demand are prepared at the zone substation level and at the subtransmission substation level. These spatial forecasts form a key input into the planning of Ausgrid's capital expenditure program.

The underlying forecast is constructed from two primary components; a near term forecast that is based on the statistically derived trend line of the weather corrected historical customer electricity demand, and a medium to long term forecast that is based on a system level econometric model. This recognises the need for the forecast model to consider the short-term trend and long-term macro econometric factors.

Both components are adjusted for out of trend impacts from embedded generation, energy storage, electric vehicles and energy efficiency. Adjustments to the forecast are also made at a spatial level to account for planned new large customer connections and planned changes to the network architecture such as load transfers. The forecast is prepared seasonally for summer and winter.

In recent years Ausgrid, along with AEMO, have adopted a more scenario-based approach to forecasting given the level of uncertainty. For the current forecast Ausgrid has developed forecasts based on the four AEMO ISP 2022 scenarios: Slow Change, Progressive Change, Step Change and Strong Electrification. Step change has been identified as the most likely option in the 2022 ISP published by AEMO in June 2022. Subsequently Ausgrid has adopted Step Change forecast as the most likely scenario on which to apply planning models and expenditure forecasts.

B.2.1 Spatial trend component of forecast

The near-term component of the forecast is based upon the local historical trend in total customer demand from both grid supplied electricity and customer embedded generation. The process for deriving the local substation forecast is as follows:

a) Raw metered electricity demand data is obtained for zone substations and subtransmission substations for 7 years at 15min intervals.

b) 10 years of weather data is obtained from the Bureau of Meteorology for weather stations across Ausgrid's network area. Each zone and subtransmission substation is assigned a representative Bureau of Meteorology weather station.

c) Network configuration data is obtained from Ausgrid's planning and customer connections groups.

d) The metered grid supplied electricity demand data is cleansed to remove abnormal loads (generally resulting from temporary network switching and abnormal configurations). This prevents abnormally switched loads from distorting historical trends.

e) The total customer electricity demand is then weather corrected based on the variable of "average ambient temperature" and subjected to Monte Carlo simulation analysis. This enables calculation of probability of exceedance (POE) levels.

f) Embedded generation demand for all 30 min intervals is modelled from a representative sample of customer interval meter data (gross metered systems) for customer solar power systems. The historical non-dispatchable embedded generation (30 min intervals) at each zone substation is derived from the embedded generation demand model and historical customer connection information. The embedded generation is then added to the weather corrected grid supplied electricity demand data to derive the customer electricity demand.

g) Maximum demand impacts from historical block loads are then identified from planning information and actual network system meter data for the historical time series. These block loads comprise all customer connections which result in a step change in demand at the zone substation. The basis for including or excluding block loads is described in section B.2.3 below. These step changes to maximum demand are then reversed from the customer electricity demand data to derive the underlying customer electricity demand data series.

h) By excluding step changes due to larger, lumpy customer loads and including the electricity supplied by customer generation, a more stable underlying trend of customer demand is revealed.

i) Regression of the resultant data series calculates the underlying rate of growth using a line of best fit at each zone and subtransmission substation. Any step changes in demand (solar, historical block loads and load transfers) are then reinserted to arrive at the starting point.

j) This local substation trend forms the basis for the first 2 years and is a component of years 3 and 4 of the forecast.

B.2.2 System level econometric model component of forecast

The medium to long term component of the forecast is based upon a system level econometric model. The econometric model is derived from key drivers at the local and system total level for both residential and non-residential elements. The process for deriving the econometric component of the forecast is as follows:

a) The residential and non-residential components of the econometric model include both price and income response elements. The residential component includes drivers for the change in real retail residential electricity prices and the change in real average household disposable income. The non-residential component includes drivers for the change in real retail non-residential electricity prices and the change in NSW Gross Value Added Services. The residential component also includes impacts from any forecast changes in population growth.

b) Forecast variation in real retail residential electricity prices, real average household disposable income, real retail non-residential electricity prices and NSW Gross Value Added Services are obtained. For the 2022 forecast, this data was obtained from the Australian Energy Market Operator (AEMO) and is the data used for AEMO's 2022 Electricity Statement of Opportunities (ESOO).

c) Due to the collinearity of the historical customer price response with historical impacts from energy efficiency improvement, the model is based upon the total 'electricity services' to customers. The 'electricity services' includes the total metered demand (grid supply), the historical demand impacts from embedded generation and the historical demand impacts from Commonwealth and New South Wales government energy efficiency programs.

d) The total metered electricity demand (grid supply) is obtained for all 30 min intervals from the bulk supply point meter data for Ausgrid's network.

e) From the interval metered data for over 500,000 customers and the total system metered electricity demand data from the bulk supply point meters, a regression model is used to calculate the separate metered electricity demand for residential customers and non-residential customers.

f) The historical demand impacts from non-dispatchable embedded generation are obtained as per item f in the description of the spatial trend forecast above. These are allocated separately for residential and non-residential customers.

g) The historical and forecast demand impacts from Commonwealth and New South Wales government energy efficiency programs are obtained for three key programs:

    i. the Minimum Energy Performance Standards (MEPS) program which sets national minimum energy performance standards for electrical appliances such as air conditioners, motors, televisions and refrigerators;

    ii. the Building Code of Australia (BCA) which sets minimum energy performance standards for buildings; and

    iii. the NSW Energy Savings Scheme (ESS) which encourages customers to invest in energy efficiency improvements in their homes and businesses.

    iv. The new Peak Demand Reduction Scheme (PDRS) introduced by NSW Government to incentivise households and businesses to reduce their consumption during peak demand hours through a certificate scheme. This element of the energy efficiency was introduced in 2020 and first formulised to use in Ausgrid's forecast in 2022.

    Ausgrid obtains the historical and forecast demand impacts for these energy efficiency programs principally from external expert advice. The demand impacts are allocated separately for residential and non-residential customers. The peak demand contribution is derived from the seasonal daily load factor on day of system peak.

h) The historical 'electricity services' for residential customers and the 'electricity services' for non-residential customers are then regressed against the separate independent variables of price and income. The econometric model determines the elasticities for both income and price for each of the residential and non-residential customer sectors.

i) Following derivation of the econometric elasticities, historical embedded generation and energy efficiency impacts are reversed out to return to the starting point. This process excludes effects likely to pollute the relationship between grid supplied electricity demand and the price and income variables. The forecasted demand impacts due to changes in price and income over time is derived by the application of the most recent econometric elasticities to econometric forecasts for future electricity price and income supplied by AEMO and as used in AEMO's 2021 Electricity Statement of Opportunities (ESOO).

j) Impacts due to new block loads, embedded generation, battery storage systems, energy efficiency, and electric vehicle take-up by customers are included as post model adjustments to the econometric model.

k) The impacts from household energy (battery) storage and rooftop solar, or distributed energy resources (DER), in the 2023 maximum demand forecast are based upon a model originally developed from external consultancy advice. The model calculates annual electricity bill savings for thousands of sample load profiles divided into representative customer types (agents) by energy consumption bands to derive likely uptake rates for DER across the Ausgrid network. In conjunction with modelled price paths for rooftop solar and batteries and future consumption and feed-in tariffs, an ROI is calculated for each representative agent over time, which in turn drives the uptake of DER. Spatial allocation of the DER is based on the current allocation of the representative customer types across the Ausgrid network area and their respective DER projections from the model, aggregated to the zone substation level. Initial DER forecast years blend from historical DER trends to model outcomes over a 5 year period

l) The impact from electric vehicles (EV) has been guided by information obtained from AEMO and external consultancy advice, supplemented by knowledge obtained from Ausgrid's involvement in EV charging trials and EV owner customer surveys. Demand impacts are derived using 5 charging typology types (Bus, Fleet, Residential, Carpark, and DC fast charge) which are allocated spatially using "points of interest" data along with NSW vehicle registration data for electric vehicles obtained from NSW Roads and Maritime Services, the 2021 ABS vehicle census by postcode data, ABS 2016 census LGA income statistics.

m) The residential component includes impacts from forecast changes in population growth based upon data from the NSW Department of Planning and ABS population projections. The population projections data from the NSW Department of Planning extracted from 2018.

n) The impact from Electrification of residential gas appliances is considered by studying the current trends on the prevalence of gas appliances in new builds, as well as existing residential gas use by LGA.

o) Each component is allocated at a zone substation level. Allocation of embedded generation and energy storage is based upon the current penetration of rooftop solar and DER model outputs and though the agent-based model as per item k. Allocation of energy efficiency impacts is based upon each substation's share of annual metered electricity volume. Allocation of impacts due to population changes is based upon the 2021 NSW Department of Planning data at the Local Government area level, adjusted for the substation service boundaries and forecast number of new dwellings from Housing Industry Association (HIA).

p) This econometric model forms the basis for years five and beyond of the forecast for each substation and a component of years 3 and 4 of the forecast.

B.2.3 Assumptions applied to substation load forecasts

Endeavour supplied substations

There are three Ausgrid zone substations not supplied from within Ausgrid's network but supplied from Endeavour Energy at 66kV and 33kV. These zone substations are Epping 66/11kV, Leightonfield 33/11kV and Hunters Hill 66/11kV. Demand from these zone substations is included in the aggregate data.

Note, in 2018 a project was committed which will see 2 more zone substations to be supplied from Endeavour Energy at 33kV. From 2021/22 both Auburn 33/11kV and Lidcombe 33/11kV zone substations will be supplied from Camelia STS in the Endeavour network area. Demand from these zone substations will remain as being included in the aggregate data.

Customer negotiated capacity

Where a customer has negotiated a higher standard of service than the default planning standard and the agreed financial terms have been met, the substation load forecast is adjusted accordingly so that this capacity is reserved for that customer.

If a customer has negotiated a lower standard of service (e.g. to reduce their costs), this is generally not incorporated into the forecast. Generally, these requests are considered during network planning, or inherent in the connection of the customer.

Embedded generation

The historical load data includes the impact of downstream embedded generation that was generating at the time of peak, consequently, the forecast includes the impact of non-dispatchable small scale generation such as rooftop solar installations.

Where a generator has a material impact on peak load that is not accurately reflected in the historical data and information is available about generator output and reliability, the forecast is adjusted to reflect the expected impact of the generator, taking into account:

- the historical reliability of the generator and expectations about its future reliability, including weather dependency where relevant;
- when the generator was installed and whether it is a temporary or permanent installation;
- contractual obligations for Ausgrid to provide backup or standby supply to a site; and
- network support agreements with the generator.

Larger generators that are relied on for network support are generally included as a negative block load. In determining whether a generator is 'large', Ausgrid uses the same approach as is used for block loads and transfers.

Capacitors for power factor correction

Reactive compensation for locations with known capacitor installations is modelled according to the following guidelines:

- Growth rates are applied to the uncompensated MVAr component of load prior to switching in Ausgrid capacitors. In other words, growth rates are not applied to capacitors.
- The amount of reactive compensation for forecast years is applied according to the nameplate step size and maximum available MVAr capacity and the application of 2 adjustment factors, the voltage adjustment factor and the operational adjustment factor.
- The voltage adjustment factor calculated at 0.84 accounts for the difference between the nameplate rated voltage and the operational voltage at the corresponding substation. The voltage adjustment is the square of the ratio of nominal operational secondary voltage at the substation over the nameplate rated voltage of the capacity i.e. $(11/12kV)^2$ or $(33/36kV)^2$.
- The operational factor accounts for the fact that capacitors are not necessarily switched in to maximise power factor. In determining the operational factor, historical patterns of capacitor switching are used.

Weather correction

Historical loads are weather corrected, to enable statistical trend line calculation of growth rates and the determination of probabilistic forecast loads. The weather correction factor is the percentage difference between the weather corrected and actual load in the most recent historical year. This correction factor can be negative, positive or zero.

Weather correction is applied according to the following rules:

Maximum demands are weather corrected with a probability of exceedance of 50% (POE50) which forms the basis for planning decision-making.

- Each substation uses 10 years of Bureau of Meteorology (BOM) data from the geographically closest BOM weather station;
- Ambient temperature is used; and
- Weather correction is applied using a Monte-Carlo simulation method to determine the POE50 maximum demand. The simulation incorporates non-working days to model the effect of substations that can peak on a non-workday.

Exceptions of weather correction

Weather correction is not applied to zone substations or subtransmission substations where the load does not exhibit weather dependency for that season, or where the load exhibits weather dependency that does not follow the general trend expected for that season based on an examination of the seasonal load versus temperature relationship. Weather correction is not applied to dedicated large customer loads (connected at the subtransmission level).

Rate of growth

The rate of growth, which may be negative, is calculated according to the following process:

- the historical block loads, load transfers, and small-scale solar generation are adjusted out of the historical weather corrected loads to reveal the underlying trend;
- the weather corrected and adjusted trends are reviewed by an expert panel to consider factors that could influence the growth rates, such as Local Government Plans; and
- a growth rate of zero is applied to dedicated customer loads (connected at the subtransmission level).

Block load transfers

Block loads for customer connections greater than a predefined threshold (as described below) are included after the application of underlying growth rates which specifically exclude these often large and lumpy changes in customer demand. A block load or transfer can result in either an increase or decrease in the forecast load (e.g. load can be transferred to or from a zone substation).

This approach to block loads has been adopted as there is a need to distinguish between natural load growth and growth arising from these larger customer connections. Large individual customer connections at a spatial level is often sporadic in nature and including such loads in the trend can lead to an over or under forecast of demand for the network asset. Removing these changes in demand for the calculation of the trend ensure that we capture the underlying trend.

Depending on the nature of block loads activity, some block loads may be individually small or there may be numerous block spot loads occurring around the same time at a given substation. To account for these possibilities, the sum of block loads for each year for each zone substation is compared to a threshold of 50A (approximately 1MVA @ 11kV). Where the sum is less than the threshold, the growth is considered to be organic and not included as a block load adjustment in the forecast.

Block loads are differentiated to account for the differing nature of these customer connections. The block load categories are late stage 11kV block loads, early stage 11kV block loads and major customer connection block loads. Scaling factors are derived from a detailed analysis of actual historical customer demand and connection data which are then applied to the requested capacity.

A summary of the block load categories is as follows:

Category	Description	Scaling Factor
Early-stage 11kV	General 11kV connections which have applied for connection	0.31
Late-stage 11kV	General 11kV connections which have received connection design approval	0.51
Major Customers	33kV+ connections or unique industry 11kV connections (e.g. rail)	based on industry

The higher resultant scaling factor for late stage 11kV block loads has been determined from detailed analysis of historical block load data and reflects the higher probability for a connection proceeding when a connection has progressed to this stage. As the 11kV scaling factors are derived from actual customer connection data and the actual resultant demand at the local 11kV panel and at the time of 11kV panel peak for real customer connections, they incorporate coincidence with peak, probability of proceeding and any industry-specific scaling factors in the case of major customer connections.

Major customer connections have a representative scaling factor applied that varies depending on the industry type and expected customer future demand profile. Where available, actual demand data from existing customers by industry type is used to derive coincidence factors. A further probabilistic factor is applied to reflect the probability of occurrence and oversizing to derive an overall scaling factor for each individual major customer connection.

Explanation of substation forecast outcome

The 2023 forecast is broadly in line with the 2022 forecast with slightly lower increase in the near-term.Overall demand rises consistently over the forecast period as demand drivers that increase demand such as Block Loads and EV uptake outweigh those that apply downward pressure to demand such as PV/Battery uptake and energy efficiency. The lower near-term forecast is largely driven by an increase in PV/Battery impacts increasing behind the meter consumption. Whilst demand drivers that lead to higher demand do increase, they are unable to entirely offset the change in PV/Battery impacts in the near term.

Summer maximum demand is expected to remain higher than winter for at least the next 10 years, however the gap between summer (higher) and winter (lower) forecasts is expected to narrow. Factors which contribute to this narrowing include the downward pressure from PV being largely absent at the time of the winter peak, combined with the fact that electrical demand reduction and energy efficiency targets have been more strongly focused on summer day loads such as air-conditioning.

DER including PV and batteries places material downward pressure on projections, however the forecast impact of energy efficiency has the largest downward impact. Electric vehicle adoption places moderate upward pressure on demand to 2031 but is expected to accelerate post 2031.

Macroeconomic income and price factors, which drive existing customer decisions affecting electricity consumption are a significant source of growth to 2031 in the data used for the 2023 forecast.

Block loads, which capture large new connections (typically >1MW up to 100+ MW) to the Ausgrid network, are also a dominant factor placing upward pressure on maximum demand growth consistent with the previous years.

The overall volume of large customer connection (block load) activity continues to be at high levels, and this has a significant impact on the 2023 forecast at a local spatial level. High-density residential development activity remains at elevated levels in the forecast, with significant investment in road and rail transport infrastructure required to service this population growth continuing through to the end of the forecast period. Rapid growth in data centre developments, large customers, and generator connection activity remains at a rate not seen in over a decade.

The 2023 forecast update includes continued improvements to forecast components including adaptation of “scenario-based” forecast as well as agent-based simulation and allocation of DER components. As previous years, it also includes revision of the latest available relevant data sources, particularly in the econometric model.

For the 2023 forecast, at the spatial level, around 78% of zones in summer and 84% of zones in winter are expected to experience growth in maximum demand over the next 5 years to 2027 (based on compound annual growth). This is an increase from 56% of zones in summer and decrease from 87% of zones in winter expected to experience growth to 2026 in the 2022 forecast.

B.3 Transmission – distribution connection point load forecast

Ausgrid prepares an annual transmission distribution connection point forecast which is provided to Transgrid in May each year as part of the annual planning review and load forecast information provisions of the NER. A forecast of future loads over a ten year forward planning period is prepared for each dual function subtransmission substation connected to the Transgrid transmission network. These load forecasts are presented in www.ausgrid.com.au/DTAPR.

As part of the annual load forecast development Ausgrid provides Transgrid with the “132kV Transgrid Report” which provides an input for their power system load flow modelling of the Ausgrid network. It contains MW, MVAr and uncompensated power factor data per year for the most recent actual year and 10 forecast years for each:

- 132kV connection point (subtransmission substations, 132/11kV zone substations and 132kV customers); and
- Zone substation supplied from other Distribution Network Service Providers (DNSPs), such as Epping, Leightonfield, and Hunters Hill, irrespective of supply voltage.

B.4 Subtransmission feeder load forecasts

Ausgrid undertakes an annual review of subtransmission feeder capacity constraints (“the feeder load forecast”) using load-flow analysis to simulate credible network contingencies. Initial analysis is conducted using network load-flow models for a forward looking 20-year period, based on:

- A 50% POE Planning Spatial Demand Step Change Forecast, including committed spot loads and uncommitted spot loads by applying a probability;
- Committed network developments and load transfers, and
- Line and cable cyclic normal and long-term emergency ratings.

The results of this analysis form an input into the Area Planning process and the Annual Capital Review process. During these processes, a cost benefit analysis based on a probabilistic criteria is undertaken in order to maximise the economic benefit of investment to relieve identified constraints.

B.5 Primary distribution feeder load forecasts

Ausgrid's primary distribution feeder forecast contains peak and minimum load values that are determined seasonally and adjusted to account for temperature variation and abnormal switching on the distribution network.
The summer and winter load scenarios are determined based on interval load data for the primary distribution feeders, zone substation interval data, customer meter data, customer connection information, and weather. This data is used to identify and exclude abnormal system states, and to estimate how this load is likely to be allocated across the network, to determine the expected load on the network during normal system conditions.
Zone substation forecast load rate of growth (ROG) and known network changes (spot loads and transfers) are then applied to estimate the demand on each feeder for the forward planning period (generally 6 years).
This forecast data is combined with network connectivity data to construct network models that can be used to simulate different scenarios to identify system limitations.

B.5.1 Load transfer capacities of zone substations

Load transfer capacity is the amount of load that can be restored in the event of a whole zone outage by switching the distribution network. The transfer capacities presented in the distribution demand forecast table as described in Section B.1 assume that a single zone is rendered out of service and the rest of the network is in system normal configuration.

Load transfers are generally considered to be a temporary solution, as transferring load to neighbouring zone substations will increase the utilisation of the destination zone and feeders. This restricts the operability of the network as the remaining distribution network is more highly utilised than planned and further restoration of subsequent contingencies may not be possible.

Transfer capacities presented in this document are based on the configuration of the HV network. Installation of additional HV interconnection and transfer capacity is typically a further consideration where it might provide a cost-effective alternative to other capital investment associated with zone substations or the subtransmission network.

Load transfer impacts are assessed on a case-by-case basis (typically in a load flow program) to ensure that the overall impact of load transfers does not overload assets in the distribution network.

Additionally, a load transfer alters the configuration of the distribution network, which may impact the capacity of subsequence load transfers. Therefore, the presented transfer capacities assume that no other load transfers have occurred.

This forecast data is combined with network connectivity data to construct network models that can be used to simulate different scenarios to identify system limitations.

B.6 Other factors having material impact on the network

B.6.1 Fault levels

Transgrid installed 50kA rated switchgear at Beaconsfield bulk supply point (BSP) during its condition driven replacement given that in some operating arrangements fault levels exceeded 40kA. Ausgrid is now installing equipment with this same fault rating in all new developments in the area. Nearby existing substations with 40kA rated switchgear, under certain operating scenarios, operate very close to their limits and this restricts some network configurations. There are numerous open points on the 132kV meshed transmission system due to these fault level limitations. These open points create more complicated switching arrangements and limit network flexibility.
The installation of the Kurri OCGT by Snowy Hydro connected at 132kV in the Newcastle BSP load area has necessitated maintenance of additional open points in the 132kV network to manage the fault level to within equipment ratings at Newcastle BSP during periods of OCGT generation.
132kV series reactors have been installed by Transgrid at Rookwood Rd BSP in part to limit fault level contribution (along with power flow control). In addition to these reactors open points were created on the 132kV network to restrict fault levels to below equipment ratings.

For a number of 132/33kV sub-transmission substations (STS) refurbishments changes have been made in the standard arrangement for neutral earthing due to review of Ausgrid network standards. This results in individual transformer neutral earthing reactors being installed in place of a common neutral earthing resistor.

The HV Network Reinforcement program includes managing fault level constraints in the HV network. These include both high and low fault level constraints. HV feeders that have high fault levels may result in damage to customer and network equipment during faults. HV feeders with low fault levels may have protection systems that cannot see or discriminate between fault locations which may lead to increased clearing times or excessive customers being interrupted. Typical solutions to these constraints include network augmentation, modifying protection settings or altering the network configuration.

B.6.2 Voltage levels

Network power flow is continuing to transition from a traditional one-way flow towards a two-way flow. A major contributor to this change up till now is the increase in CER (Customer Energy Resources), in-particular the large number of "behind the meter" solar generating plants now connected to the Ausgrid distribution network. Solar generating plants can significantly impact network voltages at times of high solar output. Our approach to managing voltages across our network involves a holistic approach, extending from BSP's to LV customers.
Voltage levels at our BSP's, STS's and zones are coordinated by local regulation schemes that are continually optimised where possible to enable transition in power flow, and where required localised network voltages are managed by traditional network options such as customer load balancing, DC tap changes and network upgrades. The traditional options are complimented with new technology trials such as community batteries, STATCOMs and Advanced Voltage Control methods. There are also network areas with specific voltage related considerations.
The meshed inner-metropolitan network is supplied by two large radial 330kV cables with very high charging capacitance. The inner-metropolitan network is also comprised of a number of long 132kV cables with significant cable charging. This means capacitor banks are required during cable outages to replace this lost reactive

support, however during low load conditions shunt reactors are required to reduce voltages. One of these cables also has a series reactor with bypass capabilities for power flow and fault level control. Capacitor banks are located at Beaconsfield BSP, Peakhurst STS and Bunnerong STS and shunt reactors at Mason Park STSS, Rookwood Rd BSP, Beaconsfield BSP and Haymarket to help manage the voltage on the 132kV meshed network.

Since the commissioning of Rookwood Rd BSP, in order to manage voltage levels in the northern Sydney area, one of the two 132kV shunt reactors at Mason Park is almost always in service with the other one switched in during times of low load. One of the reactors at Mason Park is due for repairs in December 2023.

The meshed network connected to Muswellbrook BSP is supplied from three 132kV overhead feeders and spans a significant distance to Singleton 132kV STS. Under system abnormal conditions of the 132kV subsystem and high network loading, network voltages can drop below 0.9pu at Singleton 132kV STS. Closing of the normally open 132kV interconnector to Newcastle BSP will assist in maintaining system voltages during these conditions, however the use of this interconnector is frequently constrained by abnormal local 330kV network configuration and during periods of Kurri OCGT generation. Voltage control to manage 11kV network voltages is done at zone substations using tap changing transformers and where necessary capacitor banks.

B.6.3 Other power system security requirements

Ausgrid's under frequency load shedding capabilities are assessed on a bi-annual basis to ensure compliance with NER requirements. Projects are created where compliance is no longer met due to network topology rearrangements or at the request of AEMO. Refer to 6.4 Frequency control and load shedding for more details.

B.6.4 Quality of supply

Ausgrid endeavours to provide quality of supply to customers that is necessary to operate their equipment. In general, this is achieved by operating Ausgrid's network, and requiring customers to operate their electrical installations, consistent with power quality requirements set out in the National Electricity Rules (NER), NSW Service and Installation Rules (SIR) and Ausgrid's Network Standard NS238.

Ausgrid investigates supply quality issues as they arise, including supply voltage, harmonics, and flicker. At Ausgrid, supply quality is monitored through permanent monitors at a selection of sites across the network at different voltage levels. Temporary supply quality monitors are installed at customer premises to investigate specific supply quality issues and complaints.

B.6.5 Embedded generation

Ausgrid has published on its website, guidance for proponents seeking to connect an embedded generating system under Chapter 5A or Chapter 5 of the NER. The information includes guidelines, Network Standards, Electrical Standards and proforma contracts, and Connection Application forms. A register of completed generator connections is also maintained in accordance with the NER requirements.

Ausgrid provides basic connection offer services for inverter coupled micro embedded generator units up to 200kW where augmentation of the network is not required. All other embedded generating units are offered a negotiated template connection offer consistent with Chapter 5A for units that are not registered with AEMO and Chapter 5 in the case of Registered Generators of the Rules.

Amendments to the National Electricity Rules (NER), which commenced on 18 December 2021 require all grid connected inverters to comply with the new version of AS/NZS 4777.2 which was released in December 2020. To complement the NER amendments, Ausgrid in December 2021 revised our Network Standard NS194 which sets out technical requirements for connection of generators.

Ausgrid continues to work with industry partners including the Clean Energy Council, ENA and other DNSP's to better understand the current and future network impacts of embedded generation and the emerging battery storage market and its implications within Chapter 5A of the Rules. This includes the standardisation of the power quality settings published in AS/NZS 4777.2:2020 which will allow for improved compliance and potentially increase embedded generation hosting capacities.

Ausgrid has experienced an increase in the number of customers applying to connect embedded generation. This is commensurate with the industry as a whole and the push to Net Zero. This has also led to an increase in generation proposals proceeding to the application stage.

B.7 Additional notes

B.7.1 Integrated System Plan

AEMO published the first Integrated System Plan (ISP) in 2018 and it will be updated every two years under the functions of National Electricity Rules to maintain and improve system security of National Electricity (NEM) transmission grid. It provides an actionable roadmap for eastern Australia's power system to optimise consumer benefits and provides an overview of the current state and potential future development of the NEM transmission grid.

The ISP includes a review of the:

- Optimal development path needed for Australia's energy system
- Identification of forecast constraints on the national transmission flow paths
- Whole-of-system plan to maximise net market benefits, and
- Least-regret future scenario modelling, detailed engineering analysis and cost benefit analysis.

Key features of the current ISP 2022 include:

- Supplying affordable and reliable electricity to customers in the NEM, while supporting Australia's net zero ambitions,
- Increasing the firming capacity of alternative energy sources including utility-scale batteries, hydro storage, gas-fired generation, and smart behind the meter "virtual power plants" (VPPs),
- Recognition of increased two-way electricity flow and preparation of the power system for 100% instantaneous penetration of renewables,
- Supporting the transmission projects in the optimal development path

A copy of the current ISP 2022 is available on AEMO's website at https://www.aemo.com.au. The stakeholder engagement for the development of ISP 2024 is currently underway. AEMO has published 2023 Inputs, Assumptions and Scenarios Report which will use for its planning work including in developing the draft 2024 ISP due in December 2023

B.7.2 NSW responsibility

In the ISP, network augmentation proposals by TNSPs that affect national transmission flow paths are taken into account by AEMO in the development of conceptual augmentation options and market development scenarios.

Transgrid is the Jurisdictional Planning Body (JPB) for NSW in the NEM. In this role Transgrid:

- represents the NSW jurisdiction on the Inter-Regional Planning Committee (IRPC); and
- provides jurisdictional information to the IRPC to enable it to assist AEMO in producing its annual Statement of Opportunities (SOO) and the ISP.

Accordingly, Transgrid is responsible for providing information concerning transmission developments in NSW which may affect the power transfer capacity of national transmission flow paths. Further details are available on Transgrid's website at https://www.transgrid.com.au

In addition to ISP, the NSW government has initiated an Electricity Infrastructure Roadmap (the Roadmap) which sets out the NSW Government's vision to coordinate investment in electricity transmission, generation, storage and firming infrastructure and transform the NSW electricity system into one that is cheap, clean and reliable. EnergyCo is a statutory authority and is responsible for leading the delivery of REZs as part of the Roadmap. As part of this, the State's first REZ in the Central-West Orana regions is in the development phase. Further details are available on EnergCo's website at https://www.energyco.nsw.gov.au.

Appendix C: Distribution services for embedded generating units

It is a new requirement this year for Ausgrid to provide forecast use of distribution services and hosting capacity assessments for zone substations, sub-transmission lines and transmission-distribution connection points. We are continuing to review and develop our tools and methodologies for these assessments, and to improve the availability and accuracy of data and results.

The assessment results are outlined in the online Generator Export and Hosting Capacity data file which is available for download from Ausgrid's website at www.ausgrid.com.au/DTAPR.

C.1 Zone substations

Ausgrid has considered the "use of distribution services by embedded generation units" as the total capacity collectively used by all individual customers to export their excess generation to the low voltage network at the time of maximum total export.

A comparison of three years historical data measuring aggregated exported energy and total installed distributed solar panel capacity was undertaken to examine potential predictive relationships. Analysis showed a strong correlation at all locations between the installed distributed solar capacity and their maximum export to the grid with an R^2>0.9. Given the strong correlation, Ausgrid's methodology for predicting distribution services by embedded generation units utilises forecasted total installed solar capacity and predicts the maximum aggregate export to the grid in each zone substation by applying this relationship.

The forecast PV capacity for each zone substation for the years 2022 to 2027 is extracted from the same DER model used in the maximum demand process and the average historical relationship between the installed capacity and the maximum export is applied to estimate the maximum export (MW). The forecasted installed PV capacity aligns with AEMO's Step Change scenario from the 2023 AEMO's Inputs and Assumptions file, prepared for ISP2024, applied in the Ausgrid area.

It should be noted that future changes in the consumption volume and pattern including the impact of EV, electrification, energy efficiency, modified tariffs and other sources of change can potentially have an impact on the above relationship. The impact of EVs in particular may be significant on both maximum and minimum demand in future years with increased potential for customers to charge their EVs behind the meter and therefore reduce their export ratio.

However, Ausgrid assumes for the purposes of this forecast that the number of EVs and their use pattern over the next five years will not be sufficient to significantly impact the maximum export on balance with the current trend of average PV system install size increasing. That is, the estimated current export to installed capacity ratio evident in the historical data will not significantly change due to these two competing factors during the forecast period.

C.2 Subtransmission feeders

Ausgrid has identified that some zones are experiencing reverse power flows but no system limitations of subtransmission feeders have been identified at this stage. As such, the subtransmsision feeders that are supplying these substations and are experiencing reverse power flows have not been reported at this stage.

However, there are situations where embedded generators are connected to the subtransmission network which are exporting power to the subtransmission network causing power flows through subtransmission feeders. While no system limitations have been identified as a result of these embedded generators at this stage, it is appropriate that the details of power flows on the subtransmission network and peak generation values are provided which may possibly be useful information to stakeholders.

Note that the simplistic analysis is undertaken using Ausgrid's peak power flow model which represents only one snapshot in time. The values presented in the table may vary during lighter loads and/or different operating conditions of the network.

C.3 Transmission-distribution connection points

Refer to Appendix C.2 above.

C.4 Subtransmission network hosting capacity

The hosting capacity is the amount of generation that can be added to the subtransmission network without requiring additional network investment in the network. The hosting capacity depends on a number of network parameters and limitations, including:

- Overvoltage
- Overloads including subtransmision line and transformers,
- Fault level,
- Frequency,
- Protection,
- Power quality

At this early stage of the analysis, the primary boundaries considered in finding hosting capacity are overloading, overvoltage, and fault level limitations. Typically, it is required that the power generated is able to supply both network load and losses, that the generators produce power under specified active and reactive power limits. This ensures the bus voltages are within recommended values and that there is no overloading of the subtransmission lines and transformers.

Hosting capacity is calculated at each substation connection point and subtransmission line at n (total capacity) and n-1 (firm capacity) network security levels. The approach used for the calculation of hosting capacity at subtransmsision level is as follows.

- Choose performance indices: overvoltage, overloading and fault levels.
- Determine acceptable limits of those performance indices.
- Connect a generator at the substation connection point or subtransmission line.
- Vary the size of the generator and calculate the performance indices using power flow analysis and fault level analysis.
- Find the boundaries of the generator size which is the hosting capacity at that connection point.

It should be noted that the hosting capacity is dependant on the local load where the generator is connected as there is opportunity to consume the generator load at local level without violating performance indices at upstream levels. Thus, to obtain a prudent level of hosting capacity, the minimum load level (scaling the relevant loads down) where possible is applied when calculating the hosting capacity.

The hosting capacity presented in this report is only for general guidance and would not represent the optimum hosting capacity as a number of assumptions were made during the analysis given the limited time and resources to complete detail analysis at each and every location. This is a rapid method for obtaining an initial estimation of hosting capacities. It is proponent’s responsibility to use this information with care and due diligence. The proponent must consult Ausgrid for detailed analysis of available capacity that suits a range of operating conditions at the interested location if required which ensures a more conservative and robust result can be determined for hosting capacity.

Appendix D: Glossary

ADMS	Advanced Distribution Management System
AER	Australian Energy Regulator
AEMC	The Australian Energy Market Commission is the rule maker and developer for Australian energy markets
AEMO	Australian Energy Market Operator
Asset Condition	Refers to an asset being identified as having condition issues or approaching the end of service life, and cost benefit analysis has been applied to identify an optimum solution and its timing.
BESS	Battery Energy Storage Systems
Capacity	Indicates there is a projected network capacity shortfall on the basis of expected unserved energy, and cost benefit analysis has been applied to identify an optimum solution and its timing
CBM	Condition Based Maintenance
CER	Customer Energy Resources
DER	Distributed Energy Resources
DLF	Distribution Loss Factor
DPAR	Draft Project Assessment Report
DTAPR	Distribution and Transmission Annual Planning Report prepared by a Distribution Network Service Provider under the National Electricity Rules
DNSP	A Distribution Network Service Provider who engages in the activity of owning, controlling, or operating a distribution system, such as Endeavour Energy, Ausgrid and Essential Energy
Dual Function Asset	Any part of a network owned, operated or controlled by a Distribution Network Service Provider which operates between 66kV and 220kV and which operates in parallel, and provides support, to the higher voltage transmission network and is an asset which forms part of a network that is predominantly a distribution network
EnergyCo	The Energy Corporation of NSW (EnergyCo) is a statutory authority established under the Energy and Utilities Administration Act 1987 and is responsible for leading the delivery of Renewable Energy Zones (REZs) as part of the NSW Government's Electricity Infrastructure Roadmap (the Roadmap)
ENSMS	Electricity Network Safety Management System
ESA	NSW Electricity Supply Act 1995
EUE	Expected Unserved Energy
EVCI	Electric Vehicle Charging Infrastructure
FMECA	Failure Mode Effects and Criticality Analysis
FPAR	Final Project Assessment Report
GJ gigajoule	One gigajoule = 1000 megajoules. A joule is the basic unit of energy used in the gas industry equal to the work done when a current of one ampere is passed through a resistance of one ohm for one second
GWh gigawatt hour	One GWh = 1000 megawatt hours or one million kilowatt hours
HV high voltage	Consists of 11kV and 22kV distribution assets
JPB	Jurisdictional Planning Body
LV low voltage	Consists of 400V and 230V distribution assets
kV kilovolt	One kV = 1000 volts

kW kilowatt	One kW = 1000 watts
kWh kilowatt hour	The standard unit of energy which represents the consumption of electrical energy at the rate of one kilowatt for one hour
MRA	Maintenance Requirements Analysis
MVA	(unit of electrical power) Mega Volt Amp
MVAr	MVA (reactive). Where quoted as part of a demand forecast, it is assumed that capacitors are in service.
MW megawatt	One MW = 1000 kW or one million watts
MWh megawatt hour	One MWh = 1000 kilowatt hours
N capacity	The capacity of a network (or sub-section of network) with all elements in service.
N-1 capacity	The capacity of a network (or sub-section of network) following a failure of a single critical element.
NEL	National Electricity Law
NER	National Electricity Rules
NTFP	National Transmission Flow Path
NTNDP	National Transmission Network Development Plan
OCB	Oil Circuit Breaker
POE 50	In this document, refers to a demand forecast with a 50% probability of being exceeded (i.e. 1 in 2 years)
Primary distribution feeder	Distribution line connecting a subtransmission asset to either other distribution lines that are not subtransmission lines, or to distribution assets that are not subtransmission assets
pf	Power Factor
RCM	Reliability Centred Maintenance
REZ	Renewable Energy Zones
RIT-D	Regulatory Investment Test for Distribution
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAPS	Stand Alone Power System
SCFF Cables	Self-Contained Fluid Filled Cables
SFAIRP	So Far As Is Reasonably Practicable
SOO	Statement of Opportunities
STPIS	Service Target Performance Incentive Scheme
STS	Subtransmission Substation
Subtransmission	Any part of the power system which operates to deliver electricity from the higher voltage transmission system to the distribution network and which may form part of the distribution network, including zone substations
Subtransmission system	Consists of 132kV, 66kV and 33kV assets, including dual function assets
TNSP	Transmission Network Service Provider
V volt	A volt is the unit of potential or electrical pressure
VCB	Vacuum Circuit Breaker
VCR	Value of Customer Reliability

W watt	A measurement of the power present when a current of one ampere flows under a potential of one volt
XLPE	Cross-linked Polyethylene
ZS	Zone substation

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