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Augex Overview Paper

2023-28 Revenue Proposal

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1. Purpose, structure and scope of this document

1.1. Purpose and scope of this document

This document explains and justifies at a high level our forecast of Augmentation capital expenditure (Augex) for our prescribed transmission services for the 2023-28 regulatory control period from1 July 2023 to 30 June 2028. This document supports our Revenue Proposal and references other supporting documents for further detail.

All capex is presented in real 2022-23 dollars and is expressed in total costs (i.e. direct costs plus escalations and excluding overheads).

This document explains and justifies our capex forecast for Augex only. We explain and justify our:

- opex step changes in a separate opex step change overview document, and
- other categories of capex, including Repex, Non-network ICT and Non-network Other, in separate capex overview documents.

1.2. Structure of this document

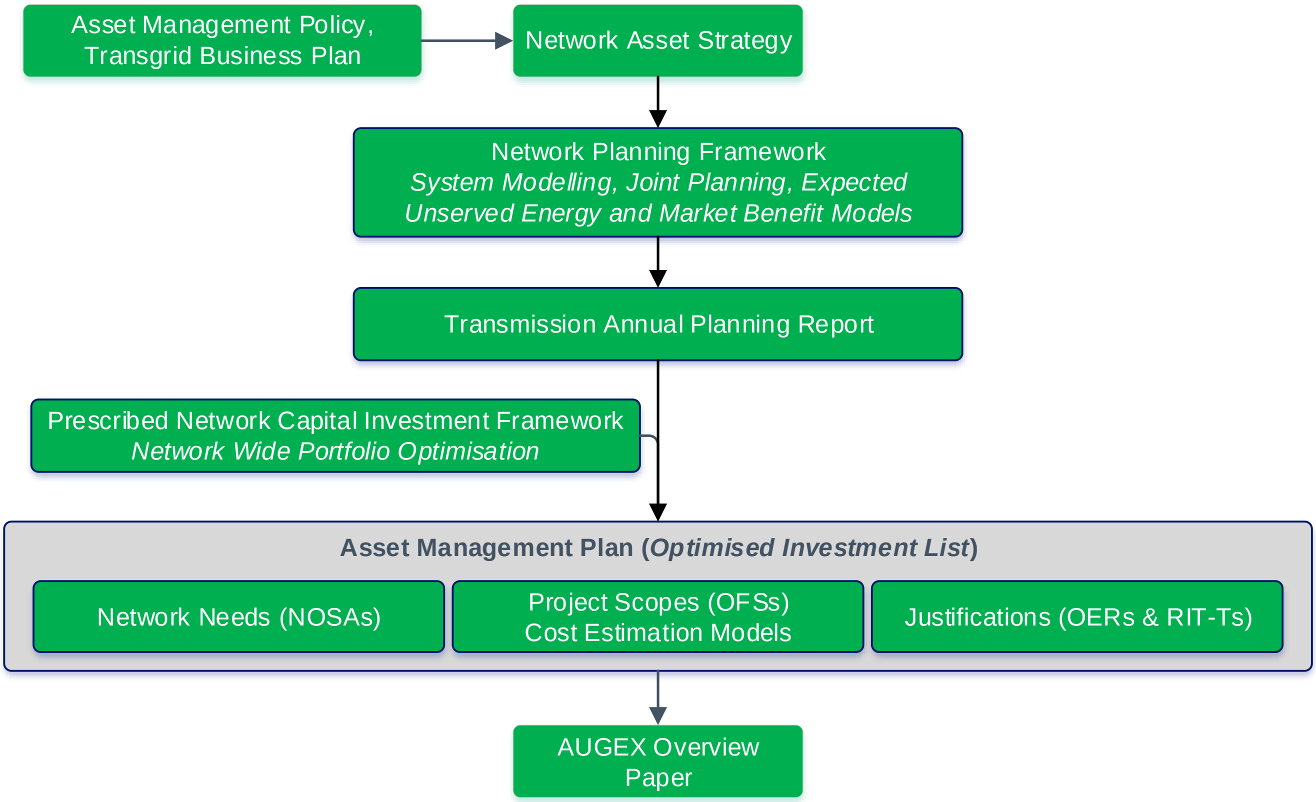
This Augex Overview Paper is structured as follows:

- chapter 1 sets out the hierarchy of supporting documents that underpin our Augex forecast
- chapter 2 discusses the nature and key external drivers of Augex
- chapter 3 overviews our Augex profile for the previous, current and forthcoming regulatory periods
- chapter 4 overviews our 2018-23 Augex and customer outcomes
- chapter 5 explains and justifies our 2023-2028 Augex forecast and customer outcomes
- chapter 6 presents our proposed contingent projects and future and actionable ISP projects
- chapter 7 explains our forecast method, inputs and assumptions used to develop our forecast Augex
- chapter 8 explains our demand and system services for the 2023-2028 period
- chapter 9 lists the supporting documentations and models
- attachment 1: provides further detail on some of the drivers of Augex
- attachment 2: summarises our major proposed Augex projects for the 2023-28 period

1.3. Supporting documents and models

Figure 1-1 illustrates the hierarchy of documents and models that support our Augex forecast, which we have submitted to the AER with our Revenue Proposal.

Figure 1-1 Hierarchy of Augex documents and models



In particular, this Augex Overview Paper is supported by our:

- **Network Asset Strategy** detailing our overarching Asset Management Strategy & Objectives
- **Network Planning Framework** which describes the management of network stability and security through network planning across our three planning horizons
- **Transmission Annual Planning Report (TAPR)** detailing our overarching strategy, plans and method for how we plan and develop the transmission network
- **Prescribed Network Capital Investment Framework** detailing our capital governance framework and our approach to portfolio optimisation of network-wide capital expenditure to demonstrate prudency, and
- **Optimised Investment List** comprising a list of projects and programs (including costs, risks, benefits, and timing) supported by:
  - **Options Evaluation Reports** (OER) and/or **Regulatory Investment Test for Transmissions** (RIT-T) – Augex project and program economic evaluation business case and regulatory justifications which apply cost-benefit analysis utilising cost-estimates, quantified risks and market benefits, to economically assess each credible option against a 'do nothing' base case - to demonstrate prudency and optimum timing of the proposed investment.

While the focus of this Paper is on Augex, our Asset Management System and Investment Governance Framework provides an integrated, holistic, optimised approach to network capital and operating expenditure. It considers the optimisation of Repex and Augex projects and programs, and the assessment of capex to opex trade-offs (including the viability of non-network alternatives). Our approach ensures there is no double counting of expenditure, and maximises the value of net benefits for our customers with a view to maintaining current performance and safety outcomes.

2. Nature and external drivers of Augex

This chapter explains:

- the nature and sub-categories of Augex and why Augex is required, and
- the key external drivers of Augex.

2.1. The nature of Augex

Our electricity transmission network forms the physical connection between regions in the National Electricity Market (NEM). It is essential for the connection of new low-cost renewable generation and stronger interconnection across the NEM to ensure the safety, security and reliability of supply and to enable customers to access affordable electricity.

Augex describes the investment required to augment the existing transmission network to meet or manage the expected demand for prescribed transmission services, comply with all applicable regulatory obligations or requirements and maintain the quality, reliability and security of the transmission network, in circumstances where the current network is no longer sufficient. In considering the need for Augex, we actively consider whether there is an alternative non-network (opex) solution that could replace of defer the need for Augex.

The key sub-categories of Augex are:

- **Demand** – Augex projects that are driven by underlying load growth or anticipated spot loads that cannot be accommodated by the existing network. Such projects address voltage or thermal constraints associated with increased maximum demand, and allow us to meet our obligations under the National Electricity Rules (NER), the NSW Reliability Standards set by IPART and the ACT Utilities Technical Regulation supply code.
- **Compliance** – Augex projects that address obligations under the NER and under our NSW and ACT licences (including the requirement for us to meet the NSW Reliability Standards set by IPART). These projects can arise from the downstream effects of new generation or load growth, as well as changes in minimum demand. This can trigger a requirement to upgrade equipment ratings (including fault level ratings) or to undertake investment to maintain quality of supply obligations.
- **Economic Benefits** – Augex projects where the cost of the project is outweighed by the expected economic benefits it generates including:
  - Economic benefits are calculated with respect to the various categories of ‘market benefit’ included under the NER in relation to the Regulatory Investment Test – Transmission (RIT-T), and therefore focus on the benefits to parties operating within the NEM.
  - Such projects can include investment to alleviate network congestion affecting low-cost generation, which can facilitate greater access to the market for that generation (lowering overall dispatch costs) and greater competition between generators (lowering wholesale market prices and potentially deferring generation and storage investment).
  - Economic benefit projects can also improve the ability of the transmission network to withstand multiple contingency events, or provide an improvement in reliability above the minimum standard, that provides a commensurate benefit to customers through the expected reduction in unserved energy.

- **System Services** – Augex projects required to maintain power system stability, such as system strength and inertia.
- **Connections** – Augex projects that enable the new connection of direct-connect transmission customers, or new distribution network feeders to supply underlying load growth or spot load in the distribution system.
- **Strategic Property** –strategic acquisition of new property (land) or easements in areas of upcoming urban development or renewable generator growth, where future transmission line development or entry to existing substations may become physically constrained in future. Such acquisitions maintain the optionality to pursue future Augex to cater for medium to long-term demand growth, and further renewable generation growth.

Attachment 1 sets out further information on the nature of Augex and these subcategories.

2.2. Key external drivers of our Augex

Augex is required to augment the existing transmission network, in response to external drivers impacting the power system.

The key drivers for Augex are:

- **Safety, security and reliability**, including:
  - **Quality of supply** – maintaining safe and reliable power quality to our customers to meet NER requirements in response to changing network configuration and conditions.
  - **Climate change** – the frequency, intensity and duration of climate-driven extreme weather events are increasing. [1] We need to continue to adapt the way we plan, operate and maintain our network to maintain our safety, security, reliability and quality of supply. This includes assessing options to mitigate against climate-driven extreme weather events and proposing investments that allow the network to continue to operate safely, securely and reliably in response to events.
- **Localised maximum demand growth**, including:
  - **Economic conditions** – this is the traditional economic growth driver for Augex, arising from increases in peak electricity demand associated with underlying load growth, the development of major new spot loads and connections (such as new industrial load and data centres), and the need for strategic land acquisition to support the ability to undertake future augmentations. Network investments are needed to address this load growth and to comply with mandated voltage and thermal stability limits and reliability standards.
- **Energy transition**, including:
  - **Changing generation mix** – the transition to a new energy market is happening quickly, as renewable costs fall, technology advances and governments commit to decarbonisation. The transition in generation mix from thermal to renewables is associated with changes in generation flows on our network. This is increasing the operational complexity of maintaining network stability

[1] NSW Treasury 2021 Intergeneration Report TTRP – An indicative assessment of four key areas of climate risk for the 2021 NSW Intergenerational Report, April 2021

and security of our network, and driving the need for compliance-related Augex around system strength, inertia, fault-levels, minimum demand and voltage stability gaps, as well as leading to market-benefit investment opportunities to relieve network congestion, where benefits exceed costs.

- **AEMO's Integrated System Plan (ISP) and the NSW Government Energy Infrastructure Roadmap** - with major policy development associated with facilitating AEMO's ISP and the NSW Government Energy Infrastructure Roadmap, there is a need for Augex to deliver major ISP projects and enable Renewable Energy Zone (REZ) development. The major transition of the energy sector towards renewable generation sources, and the potential for increased electrification, is supported by AEMO's ISP which identifies the optimal development path for eastern Australia's power system to facilitate the transformation of the energy market. It identifies the necessary investments, taking into account a range of potential future outcomes, and recommends essential actions (actionable and future ISP projects) to optimise customer benefits.

The specific drivers which have underpinned our Augex in the current period, and which form the basis from which we have developed out Augex forecast for the 2023-28 period are discussed alongside the associated Augex projects in chapters 4 and 5.

3. Comparison of Augex profile over time

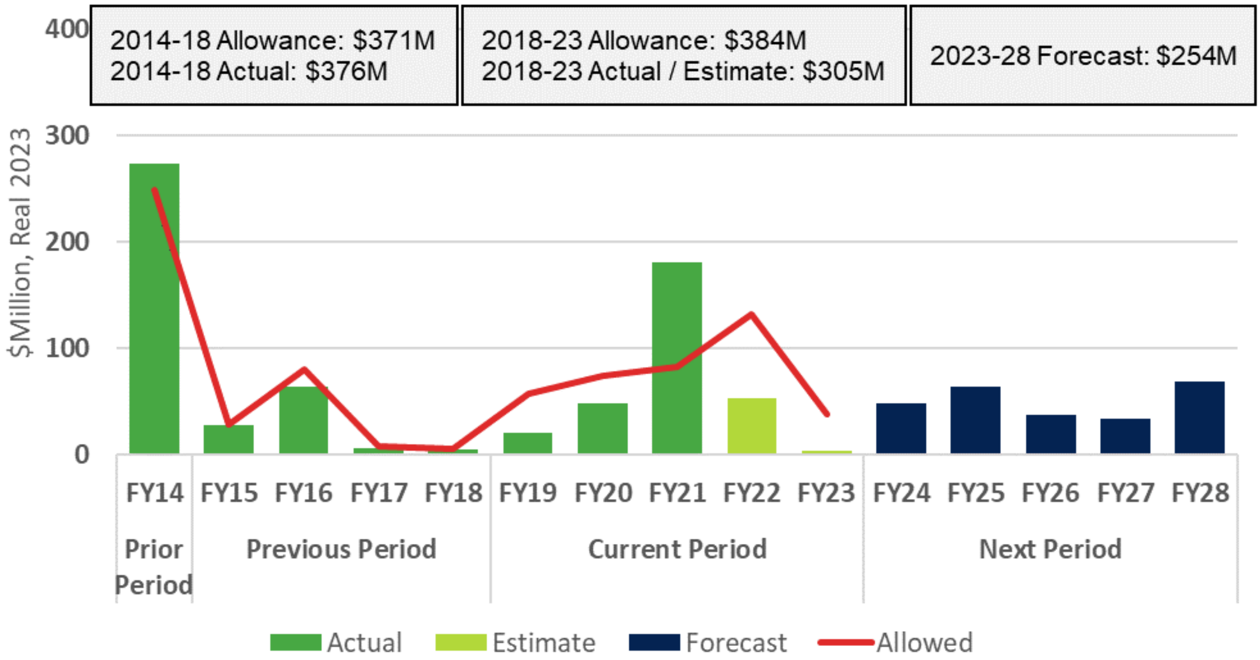
This chapter overviews our Augex profile for the previous, current and forthcoming regulatory periods.

3.1. Previous, current and forthcoming period expenditure

Figure 3.1 shows our Augex for the 2014-18, 2018-23 and 2023-28 regulatory periods,[2] and compares our 2014-18 and 2018-23 Augex with the AER's allowance.

The figure excludes capex for projects on the Australian Energy Market Operator's (AEMO) Integrated System Plan (ISP) optimal development path. These are Queensland – New South Wales Interconnector (QNI) minor upgrade, Victoria – New South Wales Interconnector (VNI) minor upgrade and Project EnergyConnect (PEC), which the AER approved through the contingent projects process during the 2018-23 regulatory period.

Figure 3-1: Actual and estimated Augex for the 2014 to 2028 period compared to the AER's allowance ($Million, Real 2022-23)



Chapters 4 and 5 present our Augex for the current and forthcoming regulatory period and the outcomes for customers.

3.2. Variance in forecast and actual capex

Table 3-1 shows our Augex for the previous (2014-18), current (2018-23) and forthcoming (2023-28) regulatory periods compared to the AER allowance and the variances.

[2] This information is presented in accordance with clause S6A.1.1(6) of the Rules

Table 3-1: Historical and forecast Augex, including contingent projects ($Million, Real 2022-23)

	2014-2018[3] Actual	2018-2023 Actual & Estimated	2023-2028 Forecast
Including Connections and ISP projects			
AER allowance, including ISP projects	371.1	2,637.7	
Actual Augex, including Connections and ISP Projects	376.3	2,041.7	253.6
Variance - Actual minus AER allowance - $ Million and %	5.2 1.4%	(596.0) (22.6%)	
Including Connections and excluding ISP projects			
AER allowance, including connection and excluding ISP projects	371.1	384.2	
Actual Augex, including Connections and excluding ISP Projects	376.3	305.4	253.6
Variance - Actual minus AER allowance - $ Million and %	5.2 1.4%	(78.8) (20.5%)	

Key drivers of the increase in Augex between the 2018-23 and 2023-28 regulatory periods are discussed in Section 8.

[3] Five years presented for comparison purposes, 2013-14 to 2017-18.

4. 2018-23 Augex and outcomes

Key messages:

Over the 2018-23 regulatory period we:

- have undertaken the following key projects to ensure we continue to meet our customers expectation for a reliable, secure power supply and comply with all applicable regulatory obligations:
  - delivering Powering Sydney's Future project (PSF), which was necessary to ensure the continued safe and reliable power supply to the people working and living in Sydney's CBD and the surrounding suburbs to meet future demand growth, at a cost of $235.2 million
  - built a new 330/132 kV substation at Stockdill to ensure continued compliance with ACT government reliability requirements, at a cost of $40.7 million
  - delivered a number of investments required to meet our network regulatory obligations and other compliance requirements, in light of load increases driven by economic growth. The most substantive of these projects have been at Macarthur and Orange, and
  - undertaken connection works relating to new loads, totalling $14.7 million.
- supported the transition to a low carbon future, through our investments in major transmission projects which underpin the Australian Energy Market Operator's (AEMO) Integrated System Plan (ISP) optimal development path, which is a whole-of-system plan to deliver an optimised energy solution for customers consistent with an electrified, low carbon future. We are delivering three of the projects on the optimal development path in the current period:
  - Queensland to New South Wales (NSW) Interconnector (QNI) minor upgrade
  - Victoria to NSW Interconnector minor upgrade (VNI)
  - Project EnergyConnect (PEC)
- Invested in new technology and infrastructure to support the continued delivery of a safe, reliable and secure power system and deliver value for customers. These included the first grid-scale battery in NSW (at Sydney West), the adoption of Smart Wires (non-network solution) to increase network capacity and reduce congestion and the roll-out of dynamic line ratings to improve our real-time utilisation of the network.

4.1. Current period Augex compared to the AER's allowance

Table 4-1 sets out our revised 2018-23 Augex proposal, the AER's Augex allowance, based on its 2018-23 Revenue Determination and our actual Augex over the 2018-23 regulatory period.[4]

Table 4-1 does not include capex associated with our approved contingent projects in the current period (i.e., QNI, VNI and PEC).

[4] This information is presented in accordance with clause S6A.1.1(6) of the Rules

Table 4-1: 2018-23 – Actual Augex compared to the AER's allowance (excl. contingent projects) ($Million, Real 2022-23)

	2018-19	2019-20	2020-21	2021-22	2022-23	Total
AER allowance	56.8	74.6	82.4	132.0	38.5	384.2
Actual/estimated	20.4	48.1	180.4	53.3	3.2	305.4
Variance (Actual/estimated and AER allowance)	(36.4)	(26.5)	98.0	(78.7)	(35.3)	(78.8)

The key drivers of our Augex over the current period are:

- PSF – this comprises 77 per cent or $235.2 million of our total Augex (excluding contingent projects), and is driven by compliance with NSW reliability standards. This is discussed in section 4.2
- Constructing a new substation at Stockdill – this comprises 13 per cent or $40.7 million of our total Augex (excluding contingent projects), and is driven by compliance with ACT government requirements. This is discussed in section 4.3
- Load growth projects – these projects comprise 4 per cent or $12.0 million of our total Augex (excluding contingent projects) and are discussed in section 4.4. The most substantive projects are:
  - the installation of a new 330/66 kV transformer at the Macarthur Bulk Supply Point (BSP) to meet demand growth in the Greater Macarthur area (at a cost of $8.2 million), and
  - the installation of new capacitor banks at our Panorama and Orange substations (at a cost of $3.9 million), to ensure NER voltage requirements continue to be met in the face of increased mining load in the area.
- Over the current period we have undertaken a number of connection works arising from joint planning with the distribution networks, to accommodate expected load growth in the distribution network. These projects comprise $14.7 million or 4.8 per cent of our Augex (excluding contingent projects) and are discussed in section 4.8.
- New technologies – notably the Sydney West battery (which we have co-funded with ARENA and a third party), which is driven by economic benefits. The regulatory funding for this project is $4.2 million or 1.4 per cent of our total Augex (excluding contingent projects). This project is discussed in section 4.6.

In addition, we have undertaken investment in new technologies funded via our NCIPAP allowance, which is in addition to the Augex allowance outlined above. This includes the adoption of Smart Wires (non-network) technology at Yass and the roll out of dynamic line ratings – these projects are discussed in section 4.6.

Table 4-2: 2018-23 – Actual Augex by sub-category (excl. contingent projects) ($Million, Real 2022-23)

Augex by driver	2018-19	2019-20	2020-21	2021-22	2022-23	Total
Base Augex	**0.3**	**0.7**	**7.7**	**6.9**	**(0.7)**	**14.8**
Compliance	-	*0.0*	*0.3*	*2.4*	-	*2.7*
Demand	*0.3*	*0.1*	*3.8*	*4.6*	*(0.7)*	*8.0*
Economic benefits	-	*0.6*	*3.6*	-	-	*4.2*
Connections	**0.9**	**1.2**	**2.1**	**9.2**	**1.3**	**14.7**
Major Augex	**19.3**	**46.2**	**170.6**	**37.2**	**2.6**	**275.9**
Powering Sydney's Future	*7.6*	*21.0*	*166.8*	*37.2*	*2.6*	*235.2*
Stockdill Dr Switching Station	*11.7*	*25.2*	*3.9*	-	-	*40.7*
QNI Minor	1.4	37.9	146.3	48.4	-	**234.1**
VNI Minor	0.4	1.8	16.8	27.0	0.0	**46.0**
PEC	3.8	24.7	264.3	409.6	753.9	**1,456.3**
Total	**25.9**	**112.6**	**607.7**	**538.3**	**757.1**	**2,041.7**

Table 4-3 sets out 2018-23 Augex by key project and sub-category of Augex.

Table 4-3: 2018-23 – Actual Augex by project (excl. contingent projects) ($Million, Real 2022-23)

Project	2018-19	2019-20	2020-21	2021-22	2022-23	Total
Compliance						
ACT Emergency Bypass Diversion at Yass	-	-	0.1	1.2	-	**1.4**
Armidale to Dumaresq QNI Transposition	-	0.0	0.2	1.1	-	**1.3**
Demand						
Macarthur second 330/66 kV transformer	0.0	0.2	0.5	5.9	1.5	**8.2**
Supply to Orange Load Growth	-	-	0.1	3.1	0.6	**3.9**
Balancing Item	0.2	(0.1)	3.1	(4.5)	(2.8)	**(4.1)**
Economic benefits						
Sydney West Battery BESS	-	0.6	3.6	-	-	**4.2**

Project	2018-19	2019-20	2020-21	2021-22	2022-23	Total
Connections	0.9	1.2	2.1	9.2	1.3	**14.7**
Major Projects						
Stockdill Dr Switching Station Header	11.7	25.2	3.9	-	-	**40.7**
Powering Sydney's Future	7.6	21.0	166.8	37.2	2.6	**235.2**
QNI Minor	**1.4**	**37.9**	**146.3**	**48.4**	**-**	**234.1**
VNI Minor	**0.4**	**1.8**	**16.8**	**27.0**	**0.0**	**46.0**
EnergyConnect	**3.8**	**24.7**	**264.3**	**409.6**	**753.9**	**1,456.3**
NCIPAP	**5.8**	**7.1**	**1.1**	**10.5**	**8.2**	**32.8**
Total (excluding NCIPAP)	**25.9**	**112.6**	**607.7**	**538.3**	**757.1**	**2,041.7**

During the 2018-23 period, we also made Contingent Project Applications (CPA) to the AER on three Actionable ISP projects. These projects have been driven by AEMO's 2020 Integrated System Plan (ISP), which seeks to coordinate and facilitate the energy transition.[5] These projects are QNI minor, VNI minor and PEC.

Table 4-4 sets out the AER's revised Augex allowance which includes incremental Augex for QNI minor, VNI minor and PEC, which it approved through the contingent project application process during the current regulatory period. These projects are discussed in section 4.9.

Table 4-4: 2018-23 - Actual Augex compared to the AER's allowance, including contingent projects ($Million, Real 2022-23)

	2018-19	2019-20	2020-21	2021-22	2022-23	Total
AER Decision	**56.8**	**74.6**	**82.4**	**132.0**	**38.5**	**384.2**
AER approved contingent project allowances	**5.1**	**105.3**	**362.9**	**1,023.2**	**757.1**	**2,253.5**
-QNI Minor	*1.0*	*76.8*	*116.1*	*41.9*	*-*	*235.7*
-VNI Minor	*0.3*	*3.8*	*14.8*	*29.8*	*-*	*48.7*
-Project EnergyConnect	*3.7*	*24.7*	*232.0*	*951.5*	*757.1*	*1,969.1*
Revised total AER allowance	**61.8**	**179.9**	**445.3**	**1,155.1**	**795.5**	**2,637.7**

5 From a fossil fuel to renewable energy based power system

	2018-19	2019-20	2020-21	2021-22	2022-23	Total
Actual / estimated (including contingent projects)	**25.9**	**112.6**	**607.7**	**538.3**	**757.1**	**2,041.7**
Variance	**(35.9)**	**(67.3)**	**162.4**	**(616.9)**	**(38.4)**	**(596.0)**

4.2. Powering Sydney's Future – maintaining reliability of supply to Inner Sydney

Table 4-2 shows that PSF has been a major component of our Augex in the current regulatory period.

PSF has been driven by the need to continue to meet reliability requirements for load in the Inner Sydney area. The PSF project is delivering a new underground electricity cable between Potts Hill and Alexandria in Sydney, to replace 50-year old cables that are reaching the end of their serviceable life. The deteriorating condition of these ageing oil-filled cables had resulted in reduced supply capability and reliability to the inner Sydney area. Analysis showed a significant risk of supply disruptions to the Inner Sydney area due to an increase in the probability of cable failures, if no investment was undertaken.

The PSF project will deliver a new 330 kV cable to greatly enhance the reliability of supply. A key benefit to customers of PSF is therefore the reduction in expected unserved energy.

In addition, after this project is completed, Ausgrid will be able to retire some of their aged oil-filled cables, which have been experiencing increased failure rates. Such failure often results in oil leaks that require remediation of any affected areas (which may include waterways). There is therefore a further benefit from PSF associated with avoiding these environment impacts, once Ausgrid's aging oil-filled cables are retired.

PSF is now nearing completion and involves:

- installing a new 20km 330 kV underground cable between Potts Hill and Alexandria
- upgrading substations at Potts Hill, Alexandria and Picnic Point
- installing additional conduits so there is space for a second cable to be added in the future as demand increases, avoiding future disruption to local communities, and
- constructing special crossings, such as cable bridges or underbores (underground crossings), for the cable circuit to cross rail corridors, rivers or parks.

PSF will secure a reliable power supply for 800,000 people working and living in Sydney's CBD and surrounding suburbs and is providing 140 jobs during construction.

Detailed planning and design for PSF started at the beginning of the regulatory period with construction commencing in August 2020. It is expected to be delivered by mid-2022, ahead of the end-2022 needs date.

Table 4-5 shows that our Augex on PSF is expected to be $235.2 million, which is $19.4 million or 7.6 per cent below the AER's allowance. The costs of delivering PSF have been strongly influenced by the increase in market costs experienced for major infrastructure projects, but offset through innovative cable technology and construction practices.

Table 4-5: Powering Sydney's Future Project ($Million, Real 2022-23)

	2018-19	2019-20	2020-21	2021-22	2022-23	Total
AER Decision	27.3	25.9	58.0	117.8	25.6	**254.6**
Actual/estimated	7.6	21.0	166.8	37.2	2.6	**235.2**
Variance	(19.7)	(4.9)	108.8	(80.6)	(23.1)	**(19.4)**

4.3. Construction of Stockdill substation – compliance with ACT Government reliability requirements

In the current regulatory period we have delivered a new 330/132 kV substation at Stockdill to ensure continued compliance with ACT government reliability requirements.

Our supply to the Australian Capital Territory (ACT) is required to meet the technical code requirements as per its Utility Services Licence obligations and the Utilities (Technical Regulation) (Electricity Transmission Supply Code) 2016.

Specifically, section 4.1.1 of the Code requires that we must plan, design, construct, test, commission, maintain, operate and manage its electricity transmission networks and geographically separate connection points that supply customers in the ACT and that will operate at 66 kV and above, whether or not those networks and connection points are in the ACT, to achieve the following:

- the provision of two or more geographically separate connection points operated at 132 kV and above to supply electricity to the ACT 132 kV network;
- at all times provide continuous electricity supply at maximum demand to the ACT 132 kV and 66 kV network throughout and following a single credible contingency event;
- until 31 December 2020, provide electricity supply at 30 MVA to the ACT 132 kV or 66 kV network within one hour following a single special contingency event and 375 MVA within 48 hours of this event; and
- from 31 December 2020, provide continuous electricity supply at 375 MVA to the ACT 132 kV network immediately following a single special contingency event and agreed maximum demand within 48 hours of this event.

Our assessment of the capability of the network to meet these requirements highlighted that the existing supply arrangement would not be compliant with the Code after 31 December 2020. Construction of a new 330/132 kV substation at Stockdill was determined to be the preferred option as it would meet the Code requirements, is technically preferred on a balance of operation and expandability and has the lower capital cost and highest Net Present Value in our economic assessment.

The Stockdill substation has cost $40.7 million and was delivered in 2020/21.

Table 4-6: Stockdill Substation ($Million, Real 2022-23)

	2018-19	2019-20	2020-21	2021-22	2022-23	Total
Actual/estimated	11.7	25.2	3.9	-	-	**40.7**

4.4. Augex projects needed to accommodate load growth

In the current regulatory period we have undertaken a number of Augex projects that have been driven by increases in load, in order to continue to comply with the NSW reliability obligations and NER obligations (most notably relating to voltage).

The most substantial of these projects was the installation of a new 330/66 kV transformer at the Macarthur Bulk Supply Point (BSP) to meet demand growth in the Greater Macarthur area. Endeavour Energy has experienced unprecedented growth in new customer connections in this area in the last five years, driven by growth in the greenfield housing market. These developments significantly increase the level of unsupportable load in Endeavour Energy's network in the event of an outage of a transformer at the Macarthur BSP. This project will benefit customers by reducing the risk of supply disruptions and provide the network supply capability to support the urban development in the Greater Macarthur area. The final project cost is expected to be $8.2 million with the transformer installation to be completed in 2023/24.

In addition we have undertaken investment in the current period to ensure supply to the Orange area continues to meet NER voltage requirements, given load growth in the area, driven by mining activity. In particular we were advised by Essential Energy that the Cadia Mine, which is a large industrial facility supplied via the Essential Energy network from our Orange North Switching Station, intends to increase its load by late 2021.

Network studies showed that the increased demand at Cadia mine could result in a reduction in network voltages (under N-1 contingency conditions), below the standards required to meet Clause S5.1.4 of the NER. In order to ensure continued compliance with the NER voltage requirements, we will install two new capacitor banks with a capacity of 10 MVAr each: one at Panorama Substation (66 kV) and the other at Orange North Switching Station (132 kV), together with the associated switchbays and secondary systems.

The total cost of this project is expected to be $3.9 million, and it will be completed in 2023/24.

4.5. Other compliance driven projects

A number of lower cost projects throughout the network have also been undertaken in the current period to ensure that our regulatory obligations are met.

This includes work relating to the ACT emergency bypass diversion at Yass (in order to comply with the ACT Electricity Transmission Supply Code) at a cost of $1.4 million and the Armidale to Dumaresq QNI transposition (to comply with Schedule S5.1a.7 of the National Electricity Rules (NER) in relation to the maximum average negative-sequence voltage) at a cost of $1.3 million.

4.6. New technologies

We are proactively seeking to develop and demonstrate the innovative solutions that will be needed to maintain safe, reliable and secure power system operations into the future, whilst also seeking out opportunities to use new solutions to reduce costs and deliver improved affordability for customers, as well as furthering our Energy Vision.

We have delivered several innovations during the current regulatory period:

- Sydney West battery, a pilot 52 MW/78 MWh Battery Energy Storage System (BESS) to be installed adjacent to the Sydney West substation for research and development into fast frequency response and synthetic inertia services, the first battery of its size in NSW. This pilot project has the potential to demonstrate that BESS can be used as a lower cost alternative to meet inertia requirements, which would deliver substantial cost savings to consumers across the NEM going forward. We partnered with ARENA and a third party to fund this project. Only $4.2 million of the total cost of the BESS is included in our Augex. This project is driven by economic benefits and we have demonstrated to the AER that the potential cost savings from this pilot more than outweigh the $4.2 million cost, even taking into account that the trial may be unsuccessful.

- dynamic line rating, where equipment has been installed on various transmission lines throughout our network (but particularly in southern and central NSW) to use real-time localised data to determine a rating for these lines closer to their physical capability rather than the static seasonal ratings that would otherwise be used. This has been progressed through two NCIPAP projects (which are not included in our Augex total), at a total cost of $4.8 million and $0.4 million:
  - use of static line ratings considers the probabilistic nature of weather and line loading conditions, to determine a maximum line rating for transmission lines, in different seasons and times of the day. However the weather data used as the basis for determining these static ratings can be conservative under certain conditions,[6]
  - adopting dynamic line ratings, which utilises real-time localised data, can at times allow these transmission lines to carry more power, closer to their physical limits within appropriate safety margins, than would be the case under static line ratings.
- the adoption of Smart Wires technology at Yass (which has been funded as a NCIPAP project outside of our Augex total). This project has cost $1.5 million.
  - we identified a constraint on power flows through the 330 kV network between the Snowy Mountains region and Canberra, due to the physical limitations of the transmission lines (with their varied thermal ratings and physical makeup) causing an uneven sharing of power flows between the lines. We anticipated that this constraint would become increasingly limiting as flows in the Southern NSW change (due to changes in the generation mix).
  - we identified an opportunity to increase the transfer capability on these lines through the installation of Smart Wires technology[7] on the Upper Tumut to Yass 330 kV transmission line. This technology enables the diversion of power flows to one of the lesser loaded lines in order to increase the notional transfer limit towards Sydney by approximately 26 MW.
  - separately, we have incorporated the Smart Wires technology as part of our VNI minor project in NSW (discussed below).
- synchronous condensers to help with system strength issue in NSW associated with the change in the generation mix. Synchronous condensers have been proposed as part of PEC.

4.7. Reprioritisation of current period capex

We have needed to re-prioritise projects across our capex portfolio during the current regulatory period to respond to emerging issues and remain within the AER's capex allowance. For Augex, this means that we

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6 This is because it does not necessarily refer to the critical constraint spans of a transmission line where conductor sagging is the constraining issue.

7 Smart Wires 'Smart Valve' technology, can be used to effectively increase or decrease the reactance of a given circuit through lagging or leading constant voltage injection. It enables the real-time control of power flow by increasing or decreasing the transmission line reactance, either pulling more current or pushing the current away onto parallel lines.

have focused on the delivery of key projects driven by our compliance obligations, including PSF, the new Stockdill substation, the additional transformer at the Macarthur BSP and the new capacitor banks in the Orange area (all discussed above).

As a consequence, we have not pursued projects which could be cancelled without effecting network reliability (which are typically market benefit projects) and we have also sought to defer projects that can be efficiently deferred into the next period.

4.8. Connections works

Over the current period we have undertaken $14.7 million of connection works, including:

- Connection of Molonglo Zone Substation, and
- Vineyard 132 kV connection - Box Hill Substation.

These projects have arisen from joint planning with the relevant distribution network, and typically relate to connections between our network and the relevant distribution network, to accommodate expected load growth in the distribution network.

4.9. Contingent projects

Contingent projects are projects which the AER has determined are likely to be required during a regulatory period, but where the exact timing and/or cost of the project is still uncertain and dependent on specific 'trigger events'. During the regulatory period, where these trigger events occur, we are able to make a 'contingent project application' (CPA or Application) to the AER, who then amends our regulatory determination to reflect the efficient costs of the contingent project.

In its 2018-23 Revenue Determination, the AER approved a number of contingent projects for:

- projects that have subsequently been identified as 'Actionable ISP projects', and therefore reflect an external policy driver. These are 'automatic' contingent projects under the new NER automatic contingent project provisions for Actionable ISP projects, and
- other projects for which we identified relevant trigger events, typically relating to changes in demand outlook or the connection of substantial renewable generation in a specific location as the relevant external driver.

During the current regulatory period, the trigger events for several of these contingent projects have occurred. We sought regulatory approval for these projects through the Application process. The AER has approved our Application's for three actionable ISP projects: QNI minor, VNI minor and PEC.

In some cases, the regulatory processes relating to contingent projects remain in train. In particular:

- HumeLink – RIT-T completed
- Maintaining a reliable supply to Broken Hill – RIT-T in progress, and
- Improving stability in south-western NSW – RIT-T in progress.

Table 4-7 sets out the AER's revised 2018-23 Augex allowance, which included its decisions on our contingent project applications for QNI minor, VNI minor and PEC, compared to our actual Augex over the current period. This shows that we expect to underspend the AER's allowance by $596.0 million. This is because PEC's delivery date is now anticipated to be 2024-25. As a result we expect to underspend the

PEC allowance in the 2018-23 regulatory period by $512.8 million.[8] We will add this pre-approved capex to our forecast for the first two years of the 2023-28 period.

Table 4-7: The AER's total Augex allowance (including Contingent Projects) for the 2018-23 period compared to our actual expenditure

	2018-19	2019-20	2020-21	2021-22	2022-23	Total
AER Decision	**56.8**	**74.6**	**82.4**	**132.0**	**38.5**	**384.2**
AER approved contingent project allowances	**5.1**	**105.3**	**362.9**	**1,023.2**	**757.1**	**2,253.5**
QNI Minor	*1.0*	*76.8*	*116.1*	*41.9*	-	*235.7*
VNI Minor	*0.3*	*3.8*	*14.8*	*29.8*	-	*48.7*
Project EnergyConnect	*3.7*	*24.7*	*232.0*	*951.5*	*757.1*	*1,969.1*
Revised total AER allowance	**61.8**	**179.9**	**445.3**	**1,155.1**	**795.5**	**2,637.7**
Actual / estimated (including contingent projects)	**25.9**	**112.6**	**607.7**	**538.3**	**757.1**	**2,041.7**
Variance	**(35.9)**	**(67.3)**	**162.4**	**(616.9)**	**(38.4)**	**(596.0)**

4.9.1. Approved contingent projects

The following projects have been approved as contingent projects during the current regulatory period. All of these are 'actionable ISP' projects as identified by AEMO to support the energy market transition. In the case of both the VNI minor upgrade and PEC, we are incorporating new technologies and innovations in order to deliver the required capabilities in a way that provides the maximum net benefit to consumers.

- **QNI minor upgrade**: this project covers a minor upgrade to the Queensland-NSW Interconnector (QNI), boosting interstate transmission capacity and increasing power flow on existing lines. This will make it easier and more efficient to share power generation across the NEM, which will help put downward pressure on customer bills. The AER contingent project allowance for this project is $235.7 million with delivery and completion of the project on track for June 2022. [9]
- **VNI minor upgrade**: this project is for the NSW component of works to upgrade the Victoria – New South Wales Interconnector (VNI), which will allow cheaper generation to be transferred between the two states. The project is also anticipated to support the development of renewable generation and ensure reliable supply during peak demand periods. The AER contingent project allowance for this

8 This amount excludes capitalised overheads.

9 The AER's allowance was $217.6 million in $2017/18, including overheads and excluding equity raising costs. The $235.7 million is in $2022/23 with assumed capitalised overheads removed.

project is $48.7 million with delivery and completion of the project on track for completion in 2022.[10] This project incorporates the use of Smart Wires technology.

- **Project Energy Connect (PEC)**: PEC will involve the construction of new 330 kV double circuit transmission lines, with approximately 800 MW transfer capacity that will connect South Australia and New South Wales, with an added connection to north west Victoria. The AER contingent project allowance for the NSW works associated with PEC is $1,969.1 million. Projects delays mean that this Project's delivery date is now anticipated to be 2024-25. As a result we expect to underspend the PEC allowance in the 2018-23 regulatory period by $512.8 million. We will add this pre-approved capex to our forecast for the first two years of the 2023-28 period. We are committed to delivering this Project in line with the total approved capex allowance of $1,969.1 million and are not seeking any additional capex for PEC over the current and next regulatory periods. PEC includes the use of synchronous condensers to address system strength issues, associated with the change in the energy mix leading to traditional power generation sources (such as coal-fired units) operating less often.

4.9.2. Contingent projects currently under regulatory consultation

In addition to the above contingent projects which have been approved, there are a number of contingent projects which remain likely to be triggered during the current regulatory period.

One of these projects is a further 'actionable ISP' project identified by AEMO as being critical to facilitating the energy sector transition and providing benefits to consumers.

- **HumeLink**: this project involves new 500 kV transmission lines which will transfer electricity from generation sources in southern NSW to major load centres, including the expanded Snowy Hydro scheme. It will connect Wagga Wagga, Bannaby and Maragle. We have completed the RIT-T process for HumeLink and anticipate providing a Contingent Project Application to the AER to cover the first stage of the works associated with HumeLink in 2022. The estimated project cost is $3,618.9 million.[11]

There are two additional Augex projects where a contingent project may be triggered during this regulatory period:

- **Improving stability in south-western NSW**: there has been significant growth in renewable connections around south-western New South Wales, which has had an impact on how this part of the power system operates, leading to a risk of power system instability. In recognition of this risks, in May 2020 AEMO implemented an operational constraint in the NEM Dispatch Engine to limit power flows and prevent this occurring. We have identified the opportunity to strengthen the transmission network to relieve this constraint and realise market benefits. The driver for this project would therefore be economic benefits by allowing more low cost renewable generation to be dispatched, offsetting higher cost thermal generation. The estimated capital cost of the preferred option in the PADR is $175.3. This project is currently undergoing a RIT-T, which is a necessary prior step before we are able to lodge a Contingent Project Application.
- **Maintaining a reliable supply to Broken Hill**: We are required to ensure reliability of supply to Broken Hill is maintained in line with the NSW Reliability Standard published by IPART. The impeding divestment of Essential Energy's gas turbines at Broken Hill, which currently provide Broken Hill with

[10] The AER's allowance was $45.0 million in $2017/18, including overheads and excluding equity raising costs. The $48.7 million is in $2022/23 with assumed capitalised overheads removed.

[11] $3,317 million in $2020-21.

power during planned or unplanned outages of the main transmission line serving the town, means that we need to identify the most efficient option for continuing to meet the reliability standard at Broken Hill. We are currently undertaking a RIT-T which is considering several options to address the reliability need, including both Augex and non-network (opex) options. Following completion of the RIT-T process, if a capex option is identified as the preferred option, we may lodge a Contingent Project Application with the AER.

We also have a number of projects for the 2023-28 regulatory period undergoing regulatory consultation which are described in Section 6.3.

4.10. Customer outcomes

Over the 2018-23 regulatory period we have delivered the following customer outcomes.

4.10.1. Safety, security and reliability

We are managing the stability of the power system to ensure the safe, reliable and secure delivery of electricity to homes and businesses across NSW and the ACT in accordance with our licence conditions. We have undertaken the following key projects to ensure we continue to meet our customers' expectation for a reliable, secure power supply whilst also complying with our regulatory obligations:

- investing in the delivery of PSF, which is necessary to ensure the continued safe and reliable power supply to the people working and living in Sydney's CBD and the surrounding suburbs to meet future demand growth. A key benefit to customers of PSF is the reduction in expected unserved energy. We also procured demand management network support services to manage the risk of unserved energy in the years before the new cable became operational
- we also built a new 330/132 kV substation at Stockdill to ensure continued compliance with ACT government reliability requirements for Evoenergy's customers, and
- as described above, we have also undertaken a number of investments required to meet our network regulatory obligations and other compliance requirements, in light of load increases driven by economic growth. The most substantive of these projects has been at Macarthur. This project will benefit customers by reducing the risk of supply disruptions and provide the network supply capability to support the urban development in the Greater Macarthur area.

4.10.2. Energy transition

Our transmission network is at the heart of the NEM, and during the current regulatory period we have supported the transition to a low carbon future, through our investments in major transmission projects which underpin AEMO's ISP optimal development path, a whole-of-system plan to deliver an optimised energy solution for customers consistent with an electrified, low carbon future.

We are on-track to deliver three of the projects on AEMO's optimal development path by the end of the current period:

- Queensland to NSW Interconnector (QNI) minor upgrade
- Victoria to NSW Interconnector minor upgrade (VNI), and
- Project EnergyConnect (PEC)

4.10.3. Technology and innovation

We have also invested in new technology and infrastructure to support the continued delivery of a safe, reliable and secure power system and deliver value for customers.

Our investments in new technology in the current period include the first grid-scale battery in NSW (at Sydney West), the adoption of ‘Smart Valves’ by Smart Wires (non-network solution) to increase network capacity and reduce congestion, and the roll-out of dynamic line ratings to improve our real-time utilisation of the network.

5. 2023-28 Augex forecast and outcomes

This chapter sets out our Augex forecast for the 2023-28 regulatory period, and the associated outcomes we intend to deliver. Further details relating to each of the projects discussed is provided in Attachment 2 and in the relevant supporting material.

This chapter focuses on those Augex investments where we have a high degree of certainty that they will be required, as a consequence of one or more of the key drivers discussed in Chapter 2. Where there is currently uncertainty in relation to the timing or cost of a project, or where the need may not eventuate, we have instead proposed those projects as contingent projects, which are discussed separately in Chapter 6.

We provide further details on the basis on which we have forecast our Augex in Chapters 7 (general forecasting approach) and 8 (external demand and system services drivers).

Key messages:

- External changes are giving rise to a number of specific challenges driving our Augex into the 2023-28 regulatory control period, many of which are highly locational.
- Investment to accommodate load growth in the Western Sydney Development area comprises [redacted] per cent ($[redacted] million) of our total Augex forecast, and is driven by the substantial increase in spot load in the Western Sydney Priority Growth area, and the need to maintain the reliability and supply capability to Endeavour Energy's Western Sydney distribution network.
- In addition [redacted] per cent ($[redacted] million) of our Augex forecast relates to strategic property acquisitions to facilitate the network developments which cater for medium term demand growth in Western Sydney.
- Other load growth projects comprise 34 per cent ($85.2 million) of our total Augex forecast, while additional compliance-driven projects comprise a further 15 per cent ($36.9 million) of the forecast.
- Our Augex forecast also includes investments to realise economic benefits - these projects comprise 16 per cent ($39.6 million) of our total forecast, and include projects in the Wagga and Molong areas. We are also proposing the implementation of special protection schemes on multiple transmission lines to manage the risk of multiple contingencies, which can be caused by climate driven extreme weather events, to improve network resilience.
- In addition to our total Augex forecast, we are proposing $16.2 million of projects to be funded via the NCIPAP allowance, to realise associated market benefits.

5.1. Forecast Augex for the 2023-28 period

Table 5-1 presents our forecast Augex capex by sub-category. The sub-categories relate to the key Augex drivers (i.e., compliance, demand and economic benefits). Major proposed Augex projects within these categories are highlighted separately.

Table 5-1: Augex by category 2023-28 ($Million, Real 2022-23)

	2023-24	2024-25	2025-26	2026-27	2027-28	Average Annual	Total 2023-28
Base Augmentation (excluding major projects)	31.3	63.6	33.9	20.4	12.5	32.3	**161.6**
Compliance	4.8	11.6	18.2	0.5	1.8	7.4	**36.9**
Demand	22.9	33.4	7.6	13.9	7.3	17.0	**85.2**
Economic Benefits	3.6	18.6	8.1	6.0	3.3	7.9	**39.6**
Connections	-	-	-	0.6	2.3	0.6	**2.9**
Strategic Property	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Sub Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Supply to Western Sydney Priority Growth area	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Augex (excl. PEC Approved)	**48.5**	**64.3**	**37.5**	**34.0**	**69.2**	**50.7**	**253.6**
PEC approved	452.5	73.9	-	-	-	105.3	**526.4**
Total Augex (incl. PEC Approved)	**501.0**	**138.3**	**37.5**	**34.0**	**69.2**	**156.0**	**780.0**
Contributions	-	-	-	-	-	-	**-**
Net Augex	**501.0**	**138.3**	**37.5**	**34.0**	**69.2**	**156.0**	**780.0**
NCIPAP	2.6	9.0	4.6	0.0	-	3.2	**16.2**

The next decade will see the transformation of the power system continue. Coal-fired generators are scheduled to retire, and record levels of new renewable generation will progress through the connection process. At the same time, electricity demand is forecast to grow, following a slight reduction during the COVID-19 pandemic, driven by economic recovery.

These external changes give rise to a number of specific challenges driving our Augex into the 2023-28 regulatory control period, many of which are highly locational as illustrated in Figure 5-1.

The major projects (and associated key drivers) of our Augex forecast are:

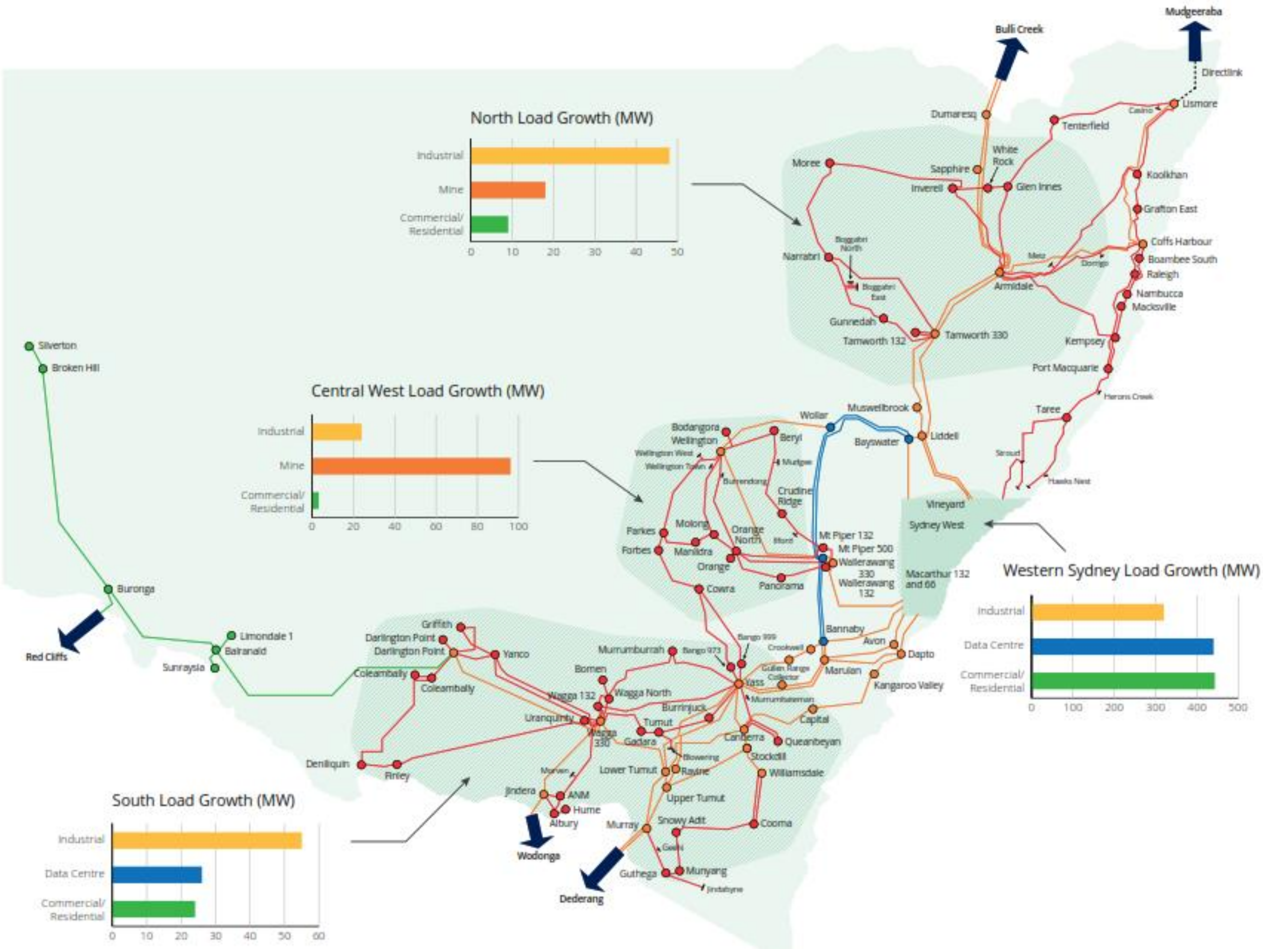
- Western Sydney Development - this comprises [redacted] per cent or $[redacted] million of our total Augex forecast and is driven by the substantial increase in underlying and spot load in the Western Sydney Priority

Growth area, and the need to maintain the reliability and supply capability to Endeavour Energy's Western Sydney distribution network. Related projects are discussed in sections 5.2.1 and 5.2.2.

- Other load growth projects – these projects comprise 34 per cent or $85.2 million of our total Augex and are discussed in section 5.2. The most material projects are:
  - Maintain Voltage in the Vineyard Area ($38.4 million)
  - Maintain voltage in the Beryl area ($20.9 million)
  - Supply to Far West NSW Network ($8.4 million)
- Additional compliance-driven projects - these projects comprise 15 per cent or $36.9 million of our total Augex and are discussed in section 5.3. The most substantive projects are:
  - Improve voltage control in Southern NSW area ($21.0 million)
  - Maintain Voltage in Greater Sydney area ($9.0 million)
  - Voltage control under light load conditions ($4.8 million).
  - Maintain voltage in Alpine area ($2.1 million in the 2023-28 regulatory period)
- Investments to realise economic benefits - these projects comprise 16 per cent or $39.6 million of our total Augex and are discussed in section 5.4. The most substantive projects are:
  - Increase capacity of 132 kV busbars at Wagga Substation ($5.2 million)
  - Manage multiple contingencies in Sydney Northwest area ($10.1 million)
  - Increase capacity for generation in Wagga North area ($10.3 million)
  - Increase capacity for generation in the Molong to Parkes area ($6.6 million)
  - Manage multiple contingencies in the Bayswater to Sydney area ($4.7 million)
  - Manage multiple contingencies in North West NSW area ($2.7 million)
- Strategic property acquisitions - this project comprises [redacted] per cent or $[redacted] million of our total Augex to cater for network developments related to medium term demand growth in Western Sydney (Supply to Western Sydney Priority Growth Area project). This acquisition is discussed in section 5.5.

In addition, we are proposing $16.2 million of projects to be funded via the NCIPAP allowance, to realise associated market benefits. These projects are discussed in section 5.7.

Figure 5-1 Augex locational drivers



5.2. Augex projects associated with load growth

Anticipated spot load development in combination with underlying load growth and increased power transfers from renewable generation are leading to thermal constraints and voltage management issues in parts of our network, triggering the need for network augmentation to remain compliant with NER requirements relating to system standards and IPART reliability standards.

Peak demand is expected to continue growing over the next regulatory period, albeit somewhat offset by the uptake of Distributed Energy Resources (DER). This will drive some network augmentation requirements.

Both AEMO and our own NSW region maximum demand forecasts show only a slight increase in maximum demand in NSW as a whole in the next decade. However some bulk supply points in the Central West (Beryl), Broken Hill, North-West Sydney (Vineyard) and Western Sydney areas are experiencing rapid load growth driven by underlying demand and new spot loads including data centres, mine expansions and new developments. The anticipated changes in demand are discussed further in Section 8.

Anticipated load growth is driving the following major projects over the next regulatory period:

- Supply to Western Sydney Priority Growth area ($[redacted] million) and
- Supply to Sydney West area ($17.4 million).

Other load growth projects comprise $85.2 million of our total Augex. The most material projects are:

- Maintain voltage in the Vineyard Area ($38.4 million)
- Maintain voltage in the Beryl area ($20.9 million)
- Supply to Far West NSW Network ($8.4 million).

5.2.1. Supply to Sydney West Bulk Supply Point

There is a need to meet growing demand in the Sydney West area, due to the connection of new data centres and ongoing development of commercial and residential lands and associated infrastructure in the area.

Currently the Sydney West BSP supplies the Endeavour Energy distribution network in the central part of Greater Western Sydney. The latest Endeavour Energy demand forecast for Sydney West BSP shows significant demand growth which is mainly driven by spot load including data centres, metro train lines and large commercial/residential development in the Aerotropolis. The POE50 summer maximum demand is forecast to exceed the Sydney West BSP firm supply capability from 2023/24, leading to an emerging risk of unserved energy.

We are exploring alternative options for ensuring continuing reliable supply to Sydney West in the face of the increase in demand, including the potential for non-network options to reduce or delay the need for network expenditure. The external driver for this investment is the need to meet IPART's reliability standards. This investment will be subject to a RIT-T.

Currently we expect the most likely option to be the installation of a new 330/132 kV transformer at Sydney West BSP. Anticipated expenditure is expected to be $17.4 million, with completion expected in 2024/25.

The need for this investment has been considered alongside the broader need to supply the Western Sydney Priority Growth area (described in Section 5.2.2).

The Supply to Sydney West Bulk Supply Point (BSP) project is being completed early within the next regulatory period (by 2024/25), delaying the need for the new BSP under the Supply to Western Sydney Priority Growth area project to 2027/28. The analysis to determine the optimal timing was undertaken through our joint planning with Endeavour Energy. These projects, along with the maintaining voltage in the Vineyard area project (described in Section 5.2.3) are supporting the growing Western Sydney load over the coming decades.

5.2.2. Supply to Western Sydney Priority Growth area

This project is being driven by the substantial increase in spot load in the Sydney Priority Growth area, and the need to maintain the reliability and supply capability to Endeavour Energy's Western Sydney distribution network.

Development of the Western Sydney International (Nancy Bird Walton) Airport was announced in 2014. Since the announcement, development of the surrounding area, both by the NSW Government and the private sector, is steadily progressing. In late 2019 the NSW Government released draft precinct plans outlining development objectives and priorities associated with the Western Sydney Parklands City, including the Aerotropolis draft precinct.

As a consequence of this planned development, the demand forecast in the Western Sydney region shows significant demand growth driven by spot loads, including data centres, metro train lines and large commercial and residential development in the Aerotropolis.

Endeavour Energy's existing zone substations will initially provide sufficient capacity for small developments, but there is insufficient sub transmission and distribution system capacity to sustain development beyond the next four to seven years.

We have four bulk supply points which currently provide supply into the area via Endeavour Energy's sub transmission and distribution network. All four bulk supply points are approaching capacity limitations in the medium term, but in particular Sydney West BSP is forecast to reach its firm supply capacity limit within five years. Therefore, establishment of additional bulk supply capacity is expected to be required.

We are currently considering options for addressing this need, through our joint planning activities with Endeavour Energy. This investment will be subject to a RIT-T.

Currently the anticipated option is to establish a new BSP at Kemp's Creek, which would involve a new 330/132 kV substation and would be supported by an expansion of Endeavour Energy's 132 kV network. Anticipated expenditure is expected to be $[redacted] million, with completion expected in 2027/28. Purchase of the land for this new BSP is included as a strategic property acquisition described in Section 5.5.

5.2.3. Maintain voltage in the Vineyard area

The North West Growth area of Sydney is currently experiencing significant load growth, driven by new development (discussed further below). This area is covered by Endeavour Energy's network, and is supplied through the Vineyard BSP.

Given the forecast demand growth in the Vineyard area, without network augmentation the total demand on the Vineyard BSP will need to be limited to 666 MVA to meet reactive margin requirements under the NER. The reactive margin at the Vineyard BSP is forecast to drop to below one percent of the fault level at those locations from summer 2024/25 under a single credible contingency of the 330 kV Line 29 that supplies the Vineyard BSP from Sydney West. To maintain the required reactive margin if the contingency occurs at or near times of high demand, load curtailment would be required from Summer 2024/25 based on the POE50 demand forecast.

The need for this project is therefore to meet the requirement for maintaining reactive margin (voltage stability) limits at the Vineyard BSP, as specified in the NER.

At this stage we anticipate that the efficient investment will be to loop-in Line 26 to the Vineyard 330 kV substation. The estimated capital cost of this project is $38.4 million, with an estimated commissioning date of 2025/26. This investment will be subject to a RIT-T.

5.2.4. Maintain voltage in the Beryl area

The Beryl area will experience demand growth into the future, attributed to the growth of individual zone substations downstream which equates to approximately 0.7 MW / year. There are also a number of mines linked to this BSP where their demand behaviour will remain at current levels.

Power system studies have identified voltage constraints and reactive margin shortfall issues in the Beryl area in the light of the latest demand forecasts, particularly when the renewable generation in the area is not dispatched. This has the potential to lead to unserved energy due to interruption of supply to loads in the area under (N-1) contingency conditions, to avoid breaching NER voltage and reactive margin requirements, and to avoid voltage collapse in the local network.

The latest forecast maximum summer demand for Beryl 66 kV BSP in 2021 is about 84 MW and is expected to increase to 90 MW in 2030; forecast maximum winter demand for Beryl 66 kV BSP in 2021 is 81 MW and is expected to increase to 87 MW in 2030.

Two renewable generators being Beryl Solar Farm (rated capacity of 87 MW) and Bodangora Wind Farm (rated capacity of 113 MW) are already in service and Crudine Ridge Wind Farm (rated capacity of 138 MW) is committed to connect.

The need for this project is therefore to meet the requirement for maintaining reactive margin (voltage stability) limits in the Beryl area, as specified in the NER, and to avoid unserved energy.

At this stage we anticipate that the efficient investment will be the installation of a 30 MVA synchronous condenser on 132 kV busbar of Beryl substation. The estimated capital cost of this project is $20.9 million, with an estimated commissioning date of 2026/27. This investment will be subject to a RIT-T.

5.2.5. Supply to Far West NSW

There is a need to meet or manage demand growth in the Broken Hill area, which is forecast to increase significantly over the next 10 years. New mine loads planning to connect to the Broken Hill area have been identified, with the forecast load expected to increase by [redacted]

This project is being driven by the need to comply with IPART's reliability standards for the Broken Hill area. Additionally, the value of unserved energy due to load shedding which would otherwise be necessary to maintain voltages within NER requirements is an economic cost that can be avoided through network augmentation.

At this stage we anticipate that the efficient investment will be to install 2 x 30 MVAr 220 kV capacitors at Broken Hill. The estimated capital cost of this project is $8.4 million, with an estimated commissioning date of 2028/29. This investment will be subject to a RIT-T.

5.3. Compliance projects

Compliance driven Augex is required to meet NER requirements, in particular to ensure compliance with:

- Voltage compliance – the minimum demand for NSW is forecast to decline over the next regulatory period, predominantly due to solar generation on the power system. This will trigger the need to undertake a program of installing reactors to maintain power frequency voltage levels as per NER S5.1a.4, and
- Power quality – Magnitude of power frequency voltage (NER S5.1.4) must be maintained as a result of the development of embedded renewable energy projects throughout NSW.

The additional compliance-driven projects comprise $36.9 million of our total Augex. The most substantive projects are:

- Improve voltage control in Southern NSW area ($21.0 million).
- Maintain Voltage in Greater Sydney area ($9.0 million)
- Maintain voltage in Alpine area ($2.1 million)
- Voltage control under light load conditions ($4.8 million)

5.3.1. Maintain voltage in Alpine area

There is need to manage and to meet expected future demand growth in the Alpine area of New South Wales supplied from Munyang and Cooma Bulk Supply Points (BSP). Munyang substation supplies the alpine villages of Thredbo and Perisher, with the majority of the Snowy Mountains winter ski resorts being supplied from this location. Reliability of supply during the ski season is of primary concern due to the number of people visiting the area, the nature of the activities and the public safety requirements during the winter period, and the demand for heating.

The winter demand is forecast to substantially increase over the next 10 years due to a number of planned spot loads associated with snow making and ski-related commercial loads in the Thredbo and Perisher. As a result of this increasing demand, voltage control will be required to maintain compliance with NER S5.1.4 under critical contingency conditions.

We have identified investment to meet this need, involving installation of static or dynamic voltage control plant at Williamsdale, Cooma or Munyang substation. The estimated cost of this investment is $2.1 million in the 2023-28 regulatory period, with an anticipated commissioning date of 2029/30 and total cost of $22.6 million. This investment will be subject to a RIT-T.

5.3.2. Maintain voltage in Greater Sydney Area

The network supplying Inner Sydney comprises hundreds of kilometres of underground high voltage cables. The increasing penetration of Distributed Energy Resources (DER) such as rooftop solar PV in the Inner Sydney area is contributing to increases in voltage levels and significant reverse reactive power flow into our network, of up to hundreds of MVAr in some locations. This can have a detrimental impact on customers' equipment and on the secure operation of the network.

Reactive support through the provision of shunt reactors (or equivalent) is expected to be required within the next five years, in order to ensure adequate voltage regulation, within regulatory requirements, for the Inner Sydney network.

We have identified investment to meet this need, involving installation of a new 100 MVAr shunt reactor at the Beaconsfield 132 kV busbar. The estimated cost of this investment is $9.0 million, with an anticipated commissioning date of 2025/26. This investment will be subject to a RIT-T.

5.3.3. Improve voltage control in Southern NSW area

AEMO's ESOO 2020 report shows that Minimum Demand in New South Wales will continue to decline over the next 3 to 5 years. The reduction in minimum demand will heighten high voltage issues already occurring in the network due to minimum demand. In addition, the NSW south west subsystem is experiencing high voltage issues at times of low demand due to reduction in Wagga area load, primarily due to Norske Skog paper mill ceasing operations (about 100 MW load decrease). The driver for this project is compliance with NER Clause S5.1.4 voltage requirements.

Our assessment of system voltages shows that over-voltages will continue to occur at the Kangaroo Valley 330kV switchyard in the event of contingency conditions, in particular if one shunt reactor in the southern region is out of service. Overvoltage also occurs at Kangaroo Valley 330 kV substation when Line 6 trips, even with all shunt reactors in service. In addition, the assessment shows that voltage control issues will continue to exist in the NSW south west subsystem (in particular at Darlington Point and Balranald) at times of light demand, in the event of contingent trip of Lower Tumut – Wagga line 051.

We have identified investment to meet this need, involving installation of reactive plant at Kangaroo Valley, Darlington Point and Buronga. The estimated cost of this investment is $21.0 million, with an anticipated commissioning date of 2026/27. This investment will be subject to a RIT-T.

5.3.4. Voltage control under light load conditions

This project is to maintain the voltage levels of the 132 kV subsystem in the North West of NSW to within permissible limits during light demand conditions, especially when reactive power support from White Rock

Wind and Solar Farm is unavailable. The driver for this project is compliance with NER voltage requirements (NER S5.1.5).

The latest demand forecasts for New South Wales show an overarching trend of reduced active power consumption and increased reactive power injection over the planning horizon at most network locations, including the North Western subsystem. Consequently, high voltage levels are likely to occur at various supply locations in this subsystem during system normal light load conditions.

Anticipated expenditure is expected to be $4.8 million, with completion expected in 2024/25 in order to ensure ongoing compliance with our regulatory obligations.

5.4. Economic benefits

A consequence of the development of renewable generation throughout the network has led to a number of constraints being imposed on multiple generators due to bottlenecks in the network. Network investment can relieve these constraints that are projected to otherwise result in generator curtailment as a result of the changing generation mix in the area and increase in renewable generation. This would provide an economic benefit through enabling additional generation from low cost and low emission sources.

We have proposed projects to increase the capacity for lower cost renewable generation through the upgrade of network elements in the Wagga, Molong and Parkes areas. A number of projects have also been identified in order to realise economic benefits by managing the risk of multiple contingency events which would otherwise paralyse parts of the network, through the installation of remedial action schemes which will improve network resilience.

Investments to realise economic benefits comprise $39.6 million of our total Augex. The most substantive projects are:

- Increase capacity of 132 kV busbars at Wagga Substation ($5.2 million)
- Manage multiple contingencies in Sydney Northwest area ($10.1 million)
- Increase capacity for generation in Wagga North area ($10.3 million)
- Increase capacity for generation in the Molong to Parkes area ($6.6 million)

5.4.1. Increase capacity of 132 kV busbars at Wagga 132/66 kV Substation

We are planning to replace the low-rated 132 kV and 66 kV busbars at Wagga 132/66 kV substation which are below the ratings of the transmission assets connected to these busbars at Wagga.

An outage of a 132/66 kV transformer on a summer day at or near times of peak load at these substations would result in the current flow in the 66 kV busbar exceeding its rating at Wagga, leading to a need to constrain load. This is also expected to occur at or near times of high renewable generation in the area, which could also lead to constraining generation. Replacement of the busbars is therefore expected to result in an overall economic benefit, through relieving the constraints on load and renewable generation in the area.

Anticipated expenditure is expected to be $5.2 million, with completion expected in 2026/27.

5.4.2. Increase capacity for generation in Wagga North area

An opportunity has been identified to upgrade the supply arrangements to the Wagga North area to alleviate potential thermal constraints due to recent renewable generation developments in the area, with a number of generators planning to connect in the near future.

In addition to the generation developments, potential large scale industrial development is expected in the area supplied by the Wagga North substation as part of the development of the Wagga Wagga Special Activation Precinct (SAP), which is a NSW government initiate to establish an economic and employment hub to accommodate regionally significant industries and businesses over the next 40 years.

There is expected to be significant economic benefits to the NEM from increasing the generation transfer capacity in the area, even without the development of the SAP.

The identified investment involves re-conducting of 9R5 and 9R6 Lines with a higher thermal capacity conductor which will increase the total transfer capacity by 95 MW.

Anticipated expenditure is expected to be $10.3 million, with completion expected in 2024/25. A RIT-T will be required for this investment.

5.4.3. Manage multiple contingencies in North West NSW area

The National Electricity Rules (NER) require us to consider the effects of non-credible (e.g. multiple) contingencies that may give rise to cascading failures. Clause S5.1.8 of the NER specifies requirements for non-credible contingencies including provision for emergency controls to minimise disruption to the transmission network and to significantly reduce the probability of cascading failure. In the event of a partial or system wide collapse, there are potential impacts, including market impacts, associated with the loss of intra-regional or inter-regional transfers, loss of supply to large load areas and high market prices.

Our studies have identified critical non-credible contingencies of [redacted] Such multiple contingency events could result in significant supply disruptions in the North West and North Coast NSW sub systems between Newcastle and Queensland, putting up to 1,000 MW at risk of involuntary load shedding.

The identified investment involves installing a control scheme using both SCADA and protection systems to mitigate this risk and provide market benefits. This investment will also aid in improving network resilience in response to increasing climate driven extreme weather events.

Anticipated expenditure is expected to be $2.7 million, with completion expected in 2025/26.

5.4.4. Manage multiple contingencies in the Bayswater to Sydney area

The National Electricity Rules (NER) require us to consider the effects of non-credible (e.g. multiple) contingencies that may give rise to cascading failures. Clause S5.1.8 of the NER specifies requirements for non-credible contingencies including provision for emergency controls to minimise disruption to the transmission network and to significantly reduce the probability of cascading failure. In the event of a partial or system wide collapse, there are potential impacts, including market impacts, associated with the loss of intra-regional or inter-regional transfers, loss of supply to large load areas and high market prices.

Our studies have identified critical non-credible contingencies of [redacted] could lead to cascading failures in the Greater Sydney load area. Such a multiple contingency event could result in voltage collapse in the Sydney area, putting up to 1,500 MW at risk of involuntary load shedding.

The identified investment involves installing a control scheme using both SCADA and protection systems to mitigate this risk and provide market benefits. This investment will also aid in improving network resilience in response to increasing climate driven extreme weather events.

Anticipated expenditure is expected to be $4.7 million, with completion expected in 2026/27.

5.4.5. Manage multiple contingencies in Sydney Northwest area

The National Electricity Rules (NER) require us to consider the effects of non-credible (e.g. multiple) contingencies that may give rise to cascading failures. Clause S5.1.8 of the NER specifies requirements for non-credible contingencies including provision for emergency controls to minimise disruption to the transmission network and to significantly reduce the probability of cascading failure. In the event of a partial or system wide collapse, there are potential impacts, including market impacts, associated with the loss of intra-regional or inter-regional transfers, loss of supply to large load areas and high market prices.

Our studies have identified critical non-credible contingencies of [redacted] could lead to cascading failures in the Greater Sydney load area. Such a multiple contingency event could result in voltage collapse in the Sydney area, putting up to 1,500MW at risk of involuntary load shedding.

The identified investment involves installing a control scheme using both SCADA and protection systems to mitigate this risk and provide market benefits. This investment will also aid in improving network resilience in response to increasing climate driven extreme weather events.

Anticipated expenditure is expected to be $10.1 million, with completion expected in 2028/29. A RIT-T will be required for this investment.

5.4.6. Increase capacity for generation in the Molong to Parkes area

A number of new renewable generator projects have connected or are expected to connect to the network west of Molong substation. Solar generation farms with combined output of 340 MW are already in service and further 270 MW of generation is committed to connect.

The existing 132 kV transmission line 94T (Molong – Orange North), has a thermal rating of 112 MVA (summer daytime). This rating is insufficient to cater for the forecast generation growth. With the current level of in-service and committed generation dispatched to their maximum capacities in network models, thermal overloading of line 94T has been observed for system normal network conditions. If the thermal capacity of line 94T remains unchanged, regular limitations to the output of generators will be required. Throughout the course of a year, a substantial quantity of low-cost renewable energy from these generators will be curtailed.

Investment is planned to undertake re-conductoring of Line 94T with a higher capacity conductor, to reach a summer day rating of at least 150 MVA.

Anticipated expenditure is expected to be $6.6 million, with completion expected in 2024/25. A RIT-T will be required for this investment.

5.5. Strategic property acquisitions

Our Augex forecast includes strategic property acquisition that allows for the development of the expected future augmentations to accommodate load growth in Western Sydney (Kemps Creek) under the Supply to Western Sydney Priority Growth Area project (described in Section 5.2.2).

The future growth in Western Sydney described in Section 5.2.2 will lead to shortfalls in supply capability from the existing network supply from our Sydney West 330/132 kV substation and the underlying Endeavour Energy network. This shortfall will require augmentation of the distribution and transmission network to support the growth within the next two decades.

A new 330/132 kV BSP to connect to our Kemps Creek 500/330 kV substation is a possible solution to support the load growth in the area with a new interconnected distribution network from Endeavour Energy. This will require land to be acquired close-by in order to build the BSP, with the undeveloped land south of Kemps Creek substation presenting an opportunity to acquire it by 2023/24 before it is built out. The land is being secured ahead of the Supply to Western Sydney Priority Growth Area project due to high interest in the area for property development. The cost of this strategic land acquisition is estimated at approximately $[redacted] million.

The proposed costs of the strategic acquisition has been informed by independent external assessment.

5.6. Connections

We have forecast the need to undertake a number of connection works in the forthcoming regulatory period, in order to accommodate load growth on various distribution networks.

5.6.1. Connection of new Strathnairn zone substation

A key connection project is the development of a new zone substation at Strathnairn.

Maximum demand in the West Belconnen area in the ACT is expected to increase due to the load growth in the new and developing suburbs of Strathnairn and Macnamara. There is a need to meet the expected demand growth in this area. The option to construct a new 132/11 kV zone substation in Strathnairn is being considered by Evoenergy to supply the forecasted load growth.

The cost of this project is $2.7 million, with timing expected to be 2027/28.

5.6.2. Condition of Ausgrid cables 9SA and 92P

Ausgrid has informed us that it plans to replace 132 kV cables 9SA and 92P Beaconsfield to Campbell St and Beaconsfield to Belmore Park. To remain compliant with the Distributor Connection Agreement, it will be necessary that the Ausgrid cables 9SA and 92P either remain connected or be replaced with an alternate supply capability.

Ausgrid has decided to replace the existing cables with new ones of similar capability. Ausgrid has requested via a formal Work Request that Transgrid carry out appropriate works to disconnect the existing cables and connect and commission the new cables at the Beaconsfield Substation end.

The cost of this project is $0.2 million, with timing expected to be 2027/28.

5.7. NCIPAP

We continuously maintains records of ratings of transmission lines, cables, feeder bays and transformers which are used to define the operating limit (rating) for each network element. Within the records, each rating includes a description of the reason for the limit, such as: due to the conductor thermal limit, or due to secondary equipment limitations. The ratings are also provided to AEMO to use as operational limits. We have used these records to prepare our Network Capability Incentive Parameter Action Plan (NCIPAP) and these were also used as the source of information in RIN table 7.9.3.

As part of analysing these limits in our NCIPAP, we have identified priority projects which will realise market benefits at a minimal cost to consumers by increasing the rating of network elements and alleviating network constraints.

The priority projects identified for the 2023-28 period include projects to remove limitations on network elements in south western and central west NSW and installation or modification of tripping schemes in south western NSW. We are also proposing the expansion of dynamic line rating installations throughout NSW and dynamic ratings for the Yass 330/132 kV transformer.

These priority projects are listed in the table below and have been endorsed by AEMO. Additional projects are being assessed and if additional priority projects are identified in consultation with AEMO during the 2023-28 regulatory period we will apply to the AER to have these added to the scheme as part of our annual STPIS reporting.

Table 5-2: NCIPAP by project ($Million, Real 2022-23)

Proposed NCIPAP project	Total estimated cost ($ million)
Increase capacity for generation between Darlington Point and Wagga The rating of the Darlington Point 330/132 kV transformers are limited to 280 MVA each due to the size of the cooler banks. This project is to upgrade cooler banks of the 330/132 kV transformers to increase the transformer rating to its nameplate rating of 375 MVA. Increasing the rating of the transformers and associated equipment to 375 MVA will provide an additional firm capacity under N-1 conditions to transfer additional renewable generation from the area into the NSW network.	4.0
Darlington Point 330/220 kV transformer tripping scheme The Darlington Point 330/220 kV Substation transformers are presently limited to 125 MVA, instead of their rated 200 MVA, due to a pre-contingent constraint imposed on them to prevent overloading of the remaining transformer following the trip of the other. This project seeks to install a transformer tripping scheme in order to remove the system normal limitation on the transformers and hence provide market benefits as this will allow additional renewable generation into the market.	0.3
Increase capacity for generation X5 voltage stability constraints Due to the inclusion of a generation in the 220 kV network of Far West NSW, preliminary voltage stability assessment in the area indicates that in order to maintain the voltage at Balranald above the required level of 0.9 pu while considering possible credible contingency events, power flow on line X5 needs to be limited. Relieving this voltage stability limit on line X5 is expected to provide market benefits by allowing additional renewable generation to the market. Assessments also indicated that reactive power injection such as capacitors at Balranald substation can relieve the line X5 limit in the range of 5 to 10 MW depending on generation dispatch at Balranald, Broken Hill and MW import from Victoria.	5.2
Increase capacity of Molong to Orange North 132kV line 94T line with dynamic ratings: The 94T is rated at 112 MVA (summer daytime), a low rating compared to the other 132 kV Lines in the Central West area and thermal overloading is expected to occur in system normal condition during high demand times. This projects deliver market benefits by optimising the rating of Line 94T, hence reducing the potential curtailment of low-cost renewable generation in the area.	0.4
Yass 330/132 kV transformer dynamic ratings Deliver market benefits by optimising the overloading capability of the Yass No.1 and No.2 330/132 kV transformers during outage condition of a single transformer. This will reduce the constraints on the low-cost renewable generation in the Southern area.	1.5
Maintain capacity during Climate Change – install dynamic line ratings on multiple lines	4.8

Proposed NCIPAP project	Total estimated cost ($ million)
Higher temperatures as a result of climate change will give rise to lower ratings on our transmission lines, and thus a reduction in current-carrying capacity across the electricity network. Coupled with demand growth and installation of renewable generation on weaker sections of the network, this could necessitate costly reinforcements and upgrades to the network. There is an opportunity to improve their utilisation by using dynamic ratings, to optimise their ratings depending on prevailing weather conditions. An added benefit is to reduce the potential curtailment of lower cost generation due to thermal limitations of these transmission lines. This would deliver market benefits from reducing constraints on dispatch of low-cost generation as a consequence of taking advantage of the additional thermal capacity of the lines.	
Total	**16.2**

6. Contingent projects

This Chapter discusses Augex that may be required in the 2023-28 period, in addition to that included in our core Augex forecast (discussed in Chapter 5).

The timing, need and/or cost of this further Augex is currently uncertain, and so we have chosen not to incorporate it in our core forecast. The investment, if required, would be progressed under the contingent project framework. This will ensure that consumers only pay for these investments once the need for them is certain, and where the AER has separately determined the efficient cost of these investments.

Contingent projects include several projects driven by external policies associated with the energy transition and reduction in emissions, including actionable ISP projects.

6.1. Actionable and future ISP projects

Our network lies at the heart of the NEM, and as a consequence, we are involved in several of the actionable ISP projects identified by AEMO as essential to enabling the energy transition and ensuring that consumers benefit from lower cost generation sources and a more resilient network across the NEM.

We will continue to progress 'Actionable ISP projects' as identified by AEMO. These have not been included as nominated contingent projects within this Revenue Proposal, as actionable ISP projects are now subject to the new 'automatic contingent project' provisions in the NER. These NER provisions include the application of a 'feedback loop' by AEMO to confirm that the project remains consistent with the ISP 'optional development path', prior to us lodging a Contingent Project Application. However, these projects are listed in Table 6-1 for completeness.

Table 6-1: Actionable and Future ISP Projects (2023–28)

ISP Project	2023-28 estimated cost ($ million)	Total estimated cost ($ million)
HumeLink – Actionable	3,619	3,619
VNI West – Actionable	1,697 (includes NSW and VIC components)	3,091 (includes NSW and VIC components)
Sydney Ring (Reinforcing Sydney, Newcastle and Wollongong Supply) - Actionable	925	925
QNI Connect – Future	159 (includes NSW and QLD components)	1,316 (includes NSW and QLD components)
Total	**6,399**	**8,951**

Source: HumeLink RIT-T PACR and AEMO draft 2022 ISP

6.2. System strength projects

In October 2021 the AEMC made a Rule change which reforms the 'system strength' framework in the NEM, to reflect the energy sector transition.[12] The Rule change resulted from a request from us, and the AEMC expects that the changes will lower to the cost to consumers of providing system strength. The reform seeks to facilitate simpler, faster and more predictable connections to the grid for new generators, such as renewables and batteries.

System strength relates to the stability of the voltage waveform. System strength services are necessary to keep the power system stable as the generation mix changes and large, synchronous generators retire. We expect that the provision of system strength services in New South Wales will become important over the next regulatory period, with the retirement of Vales Point Power Station.

Under the new Rules, AEMO is responsible for determining new system strength standards which we are then required to reflect in our network planning, to identify the least cost way to deliver these standards.

For the 2023-2028 regulatory period, investment required to meet the new system strength standards is automatically taken to be a contingent project (provided that the cost of the investment is more than $30 million or 5% of our MAR for the first year of the period).[13] We are not required to provide an estimated value of this investment as part of our proposal, and the AER is not required to approve a contingent project for this investment as part of its determination on our proposal.

The NER sets out deemed trigger events for a system strength contingent project as:

1. Transgrid's Board has committed to proceed with the system strength project subject to the AER amending Transgrid's revenue determination in accordance with clause 6A.8.2.
2. Unless the system strength project is not subject to the RIT-T due to clause 5.16.3(a):
    a. Transgrid has issued a project assessment conclusions report that meets the applicable requirements of new clause 5.16.4 and which identifies the project as the preferred option; and
    b. the time period in rule 5.16B(c) for giving a dispute notice has elapsed and no dispute notice been given to the AER under rule 5.16B(c) or, if a dispute notice has been given, then in accordance with rule 5.16B(d), the dispute has been rejected or the project assessment conclusions report has been amended and identifies the system strength project as the preferred option.

We have included a contingent project should AEMO declare a system strength shortfall during the transitional period of the rule change as described in Section 6.4.1.

6.3. Projects undergoing a RIT-T

We have included projects currently undergoing a RIT-T as contingent projects where the RIT-T is expected to be completed before we submit our Revised Revenue Proposal to the AER in November 2021. These projects are listed in Table 6-2. We will include the costs of the preferred options in our capex forecast in our Revised Revenue Proposal.

12 AEMC, Rule determination - National Electricity Amendment (efficient management of system strength on the power system) rule 2021

13 NER 11.143.18

Table 6-2: 2023-28 Augex Major Projects – undergoing RIT-T

Major Projects – undergoing RIT-T	Total estimated cost ($ million)	Expected completion
Managing risk on Line 86 (Tamworth – Armidale)	331	2027-28
Improving stability in south western NSW	175	2024-25
Supply to North West Slopes	168	2027-28
Supply to Bathurst, Orange and Parkes Stage 1	117	2026-27
Total	**792**	

6.3.1. Managing Risk on Transmission Line 86

Transmission line 86 runs between Tamworth and Armidale and forms part of the Queensland – New South Wales Interconnector (QNI) path. Line 86 is a wood pole 330 kV transmission line, the only 330 kV transmission line of its type on the network, and is now exhibiting advanced signs of wood pole rot and deterioration increasing the probability of failure.

The driver for this project is the condition based replacement of the wood poles which are reaching end of life, however, there is an opportunity to address this through an Augex solution which also increases the power transfer capacity between Tamworth and Armidale which is expected to deliver material market benefits due to its location on the QNI path and renewable generation connections expected in the area.

We have commenced the RIT-T process to select the preferred option for this need and given the uncertainty on whether the final solution, if it is a network solution, will be Repex or Augex, we have included this as a contingent project. We intend to conclude the RIT-T and select a preferred option to reflect in our final revenue proposal submission.

Table 6-3 Transmission Line 86 replacement contingent project

Project details	Particulars
Current expected timing	2027/28
Status	Currently undergoing a RIT-T
Estimated total Augex	$331 million
Estimated Augex in the 2023-28 regulatory period	$331 million

6.3.2. Improving stability in south-western NSW

This contingent project reflects a project included in our current determination (‘Support South Western NSW for renewables’).

South-western NSW has seen significant growth in renewable connections to the transmission network as part of the wider energy market transition. Approximately 1288 MW of renewable generation has connected in the area since December 2015. This is having an impact on how this part of the power system operates. Changes in power flows are expected to lead to an increasing risk of power system instability going forward. Currently, the only way of managing this risk is to constrain generation in south-western NSW. In recognition of the risks to future power system stability, in May 2020 the Australian Energy Market Operator (AEMO) implemented an operational constraint in the NEM Dispatch Engine to limit power flows and prevent this occurring.

We have identified the opportunity to strengthen the transmission network to relieve this constraint and provide wider market benefits to the NEM. We are currently progressing a RIT-T relating to investments that would address this constraint ('Improving stability in South-western NSW RIT-T').

As the RIT-T process in still in train, there is uncertainty in relation to its outcome and the timing of any investment. We intend to conclude the RIT-T and select a preferred option to reflect in our final revenue proposal submission.

Table 6-4 Improving stability in south-western NSW contingent project

Project details	Particulars
Current expected timing	2024/25
Status	Currently undergoing a RIT-T
Estimated total Augex	$175 million
Estimated Augex in the 2023-28 regulatory period	$127 million

6.3.3. Supply to North West Slopes

Demand in the Narrabri and Gunnedah area is forecast to increase due to new and existing developments in the area. This is driven by a number of substantial industrial loads anticipated to connect.

Power System studies indicate that the network will reach voltage stability and thermal limits with the expected load growth. Under this need, suitable network augmentation options are being identified to manage these constraints.

NER requirements relating to voltage compliance and IPART reliability standards, due to load growth, is driving the need for this project. Schedule 5.1.4 of the NER requires us to plan and design equipment for voltage control to maintain voltage levels within 10 per cent of normal voltage. The NER also requires the power system to be operated in a satisfactory operating state, which requires voltages to be maintained within these levels, both in normal operation and following any credible contingency event.

Our planning studies show that the current North West Slopes network will not be capable of supplying the combined increases in load in the area without breaching the NER requirements and that voltage-limited constraints will have to be applied in the 132 kV supply network if action is not taken.

Moreover, in addition to the longer-term voltage constraints identified, our planning studies show that the increased demand will also lead to thermal constraints in the region, particularly during times of low renewable generation dispatch in the region. If the longer-term constraints associated with the load growth in the North West Slopes are unresolved, it could result in the interruption of a significant amount of electricity supply under both normal and contingency conditions due to voltage and thermal limitations in the area.

We have commenced the RIT-T process to select the preferred option for this need and given the uncertainty on the preferred solution we have included this as a contingent project. We will include the preferred option in our Augex forecast in our Revised Revenue Proposal.

Table 6-5 Supply to North West Slopes contingent project

Project details	Particulars
Current expected timing	2027/28
Status	Currently undergoing a RIT-T
Estimated total Augex	$168 million
Estimated Augex in the 2023-28 regulatory period	$166 million

6.3.4. Supply to Bathurst Orange and Parkes Stage 1

The latest forecasts indicate that electricity demand is expected to increase substantially in central west NSW around Bathurst, Orange and Parkes. The expected load growth is mainly due to the expected expansion of some existing large mine loads in the area, the planned connection of new mining and industrial loads and general load growth around Parkes, including from the NSW Government's Parkes Special Activation Precinct. Power system studies indicate that the network will reach voltage stability limits with the expected load growth. Suitable network augmentation options are being identified to manage these constraints.

Compliance with NER requirements relating to voltage compliance, due to load growth, is driving the need for this project.

Schedule 5.1.4 of the NER requires us to plan and design equipment for voltage control to maintain voltage levels within 10 per cent of normal voltage.[14] The NER also requires the power system to be operated in a satisfactory operating state, which requires voltages to be maintained within these levels, both in normal operation and following any credible contingency event.[15] Our planning studies show that the current central west network will not be capable of supplying the combined increases in load in the area without breaching the NER requirements and that voltage-limited constraints will have to be applied in the 132 kV supply network if action is not taken.

If the longer-term constraints associated with the load growth in Orange and Parkes areas are unresolved, it could result in the interruption of a significant amount of electricity supply under both normal and contingency conditions due to voltage and thermal limitations in the area.

[14] These levels are specified in Clause S5.1a.4.

[15] These requirements are set out in Clauses 4.2.6, 4.2.4 and 4.2.2(b) of the NER. The requirement for secure operation of the power system in Clause 4.2.4 requires the power system to be in a satisfactory operating state following any credible contingency event, that is, to maintain voltage within 10 per cent of normal voltage following the first credible contingency event.

Stage 1 of this project addresses load growth associated with committed and expected spot loads. It may involve installing dynamic reactive support at Panorama and Parkes substations. Should the high demand forecast scenario eventuate with additional spot load connections being committed, Stage 2 of the project will be required which is described in Section 6.4.5.

This project is currently undergoing the RIT-T.

This project is currently anticipated to cost around $117 million in total, with completion expected in 2025/26. The RIT-T is exploring whether there are cost effective non-network options to defer this expenditure.

Table 6-6 Supply to Bathurst Orange and Parkes Stage 1 portion of contingent project

Project details	Particulars
Current expected timing	2026/27
Status	Currently undergoing a RIT-T
Estimated total Augex	$117 million
Estimated Augex in the 2023-28 regulatory period	$117 million

6.4. Standard contingent projects

We have included a number of specific contingent projects in our Proposal.

Table 6-2 below summarises these contingent projects, and the associated trigger events we propose in relation to each one.

Table 6-7: Proposed contingent projects for the 2023-28 period ($Million, Real 2022-23)

Proposed contingent project	Total estimated cost 2023-28 ($ million)	Proposed trigger
Meeting NSW system inertia requirement	105	(a) Notice by AEMO of the existence of an inertia shortfall in the New South Wales region, in line with NER 5.20B, and (b) Unless the inertia project is not subject to the RIT-T due to clause NER 5.16.3(a)(10): Successful completion by Transgrid of a RIT–T that demonstrates that transmission investment is the preferred option (or part of the preferred option).
Meeting NSW system strength requirement during the system strength transition period	284	(a) Notice by AEMO of the existence of a system strength shortfall in the New South Wales region, in line with NER 11.143.14 (b) Unless the system strength project is not subject to the RIT-T due to clause 11.143.16: Successful completion by Transgrid of a RIT–T that demonstrates that transmission investment is the preferred option (or part of the preferred option).
Supply to Bathurst, Orange and Parkes Stage 2	95	(a) One or more of the following: (i) Total demand in the Orange area exceeds 355 MW, or (ii) Total demand in the Parkes area exceeds 155MW, and (b) Successful completion of a RIT-T demonstrating that increasing capacity of the network in the Bathurst, Orange and Parkes areas is the option or part of the option that maximises positive net economic benefits.
Improve capacity of Southern NSW lines for renewables	276	(a) New generation of more than 1,000 MW is committed in Southern and/or South western NSW (b) Successful completion of a RIT-T demonstrating that increasing capacity of the network in southern NSW is the option or part of the option that maximises positive net economic benefits
Supply to ACT network capability	71	(a) One or more of the following: (i) Combined demand between Canberra to Williamsdale exceeds 890 MW (ii) The ACT Utilities (Technical Regulation) (Electricity Transmission Supply Code) makes a change to the agreed maximum demand under a special contingency event, and (b) Successful completion of a RIT–T that demonstrates that transmission investment is the preferred option (or part of the preferred option)

Moree Special Activation Precinct	42	(a) Moree total demand forecast exceeds 50 MW (b) Successful completion of a RIT–T that demonstrates that transmission investment is the preferred option (or part of the preferred option)
Strategic Easement acquisition for supply to Sydney from the south	252	(a) Inclusion of Southern 500 kV Ring (supply to Sydney, Newcastle and Wollongong future ISP project, southern section) in optimal development path in 2022 (or subsequent) ISP, and (b) Rezoning of land along the proposed easement between South Creek and Greendale from rural to residential, commercial or industrial.
Manage increased fault levels in Southern NSW	51	(a) Successful completion of a RIT–T that demonstrates that transmission investment in the HumeLink Project is the preferred option (or part of the preferred option) (b) Contingent Project Application approval for the HumeLink Project
Total	**1,176**	

6.4.1. Meeting NSW system inertia requirement

Closure of synchronous generation may lead to an inertia shortfall. We have included investments to provide this system service as a contingent project in our Proposal, which would only be triggered when required by AEMO.

Table 6-8 Meeting NSW system inertia requirement contingent project

Project details	Particulars
Current expected timing	2030/31
Status	Preliminary activities
Estimated total Augex	$263 million
Estimated Augex in the 2023-28 regulatory period	$105 million

6.4.2. Meeting NSW system strength requirement during the system strength transition period

The new system strength framework comes fully into effect from 1 December 2025. Prior to this, a 'system strength transition period' applies, governed by transitional provisions in the NER. We have included a contingent project in our proposal (see below) to cover any system strength investments we may be required to make during this transition period as a consequence of a declaration of a system strength shortfall by AEMO.

Table 6-9 Meeting NSW system strength requirement contingent project

Project details	Particulars
Current expected timing	2025/26
Status	Preliminary activities
Estimated total Augex	$641 million
Estimated Augex in the 2023-28 regulatory period	$284 million

6.4.3. Increase capacity of Southern NSW lines for renewables

There is an opportunity to increase capacity of the Southern NSW lines to accommodate future renewable generators.

We have received applications totalling 1,900 MW for renewable generation projects in Southern NSW, together with the committed Snowy 2.0 pumped hydro development of 2,000 MW. The limited capacity of the existing 330 kV transmission lines in the area will result in output limitation of connecting generators as the amount of generation in the area increases.

Further development of the Southern NSW transmission lines will results in the network being capable of hosting more renewable energy and sharing both storage and firming services between other areas in the network. It is expected that increasing capacity of the Southern NSW lines will bring a range of classes of market benefits.

Table 6-10 Increase capacity of Southern NSW lines for renewables contingent project

Project details	Particulars
Current expected timing	2029/30
Status	Preliminary activities
Estimated total Augex	$394 million
Estimated Augex in the 2023-28 regulatory period	$276 million

6.4.4. Supply to ACT network capability

We have regulatory requirements to restore supply to Canberra for special contingency events. The special contingency events are the loss of the entire substation (e.g. Canberra, Stockdill or Williamsdale). Within 1 hour of one of these events we are required to supply 375 MVA of load and within 48 hours is required to supply a 2017 agreed maximum demand of 657 MVA (632 MW, 180 MVAr).

The total winter demand for ACT in 2021 is 692 MW and is expected to grow to 728 MW by 2030, which is higher than agreed 632 MW. This means that total winter load, in case of a special contingency such as loss of Canberra substation, could not be supplied using existing operational arrangements.

If the agreed Maximum demand of 657 MVA was altered by the UTR, a different permanent supply arrangement would be required to comply with the regulatory requirement. A major transmission network upgrade would be required. This could include a second transformer at Stockdill substation, termination of line 7 into Stockdill and Canberra and reactive support such as SVC at Williamsdale.

Table 6-11 Supply to ACT network capability contingent project

Project details	Particulars
Current expected timing	2028/29
Status	Preliminary activities
Estimated total Augex	$95 million
Estimated Augex in the 2023-28 regulatory period	$71 million

6.4.5. Supply to Bathurst Orange and Parkes Stage 2

The latest forecasts indicate that electricity demand is expected to increase substantially in central west NSW around Bathurst, Orange and Parkes. The expected load growth is mainly due to the expected expansion of some existing large mine loads in the area, the planned connection of new mining and industrial loads and general load growth around Parkes, including from the NSW Government's Parkes Special Activation Precinct. Power system studies indicate that the network will reach voltage stability limits with the expected load growth. Suitable network augmentation options are being identified to manage these constraints.

Compliance with NER requirements relating to voltage compliance, due to load growth, is driving the need for this project. We are undertaking a RIT-T for Stage 1 of this project as described in Section 6.3.4 however if additional planned loads commit then there will be a need for further investment to ensure voltage compliance. Given the uncertainty on the timing of these future spot load connections, we have included Stage 2 as a contingent project.

Table 6-12 Supply to Bathurst Orange and Parkes Stage 2 portion of contingent project

Project details	Particulars
Current expected timing	2030/31
Status	Currently undergoing a RIT-T
Estimated total Augex	$405 million
Estimated Augex in the 2023-28 regulatory period	$95 million

6.4.6. Moree Special Activation Precinct

The NSW Government is preparing a plan to develop the Moree area to provide a new business hub, specialising in agribusiness, logistics and food processing. With national and global connections by road, rail and air, the Moree Special Activation Precinct will become NSW's northern hub for horticulture and diversified agriculture production, while continuing to recognise and respect the region's strong connection to country.

Initial joint planning discussions with Essential Energy have identified a future requirement to augment the transmission network. This augmentation would provide reliable supply to the Moree area following demand increase beyond the capabilities of the existing network.

Table 6-13 Moree special activation precinct contingent project

Project details	Particulars
Current expected timing	2027/28
Status	Preliminary activities
Estimated total Augex	$42 million
Estimated Augex in the 2023-28 regulatory period	$42 million

6.4.7. Strategic easement acquisition for supply to Sydney from the south

Future growth in Western Sydney is expected to be significant as it develops in importance into one of Three Cities in the Greater Sydney Region. As it develops, the population in Western Sydney is expected to grow to over 1 million people by 2036 and 1.5 million people by 2056 according to NSW Government plans.[16] Consequently, we consider there is a need to make strategic land acquisitions in Western Sydney to support a future 500 kV transmission corridor in the next few decades which is identified in the 2020 ISP as a future ISP project, “Reinforcing Sydney, Newcastle and Wollongong Supply”, and in the draft 2022 ISP as an actionable ISP project, “Sydney Ring”. The cost of strategic land acquisitions in Western Sydney is estimated at approximately $252 million that would support the development of the new transmission corridor.

Table 6-14 Strategic easement acquisition for supply to Sydney from the south contingent project

Project details	Particulars
Current expected timing	2025/26
Status	Preliminary activities
Estimated total Augex	$252 million
Estimated Augex in the 2023-28 regulatory period	$252 million

6.4.8. Manage increased fault levels in Southern NSW

A consequence of the various major ISP projects (including PEC, VNI West and HumeLink) as well as the development of Snowy 2.0 and the increase in the connection of renewable generation, is the need to undertake a number of ‘deep augmentation’ investments relating to fault level upgrades in Southern NSW. This will avoid existing equipment exceeding fault level ratings.

We have undertaken a review of four key sites, Murray, Lower Tumut, Upper Tumut and Wagga, in order to underpin our forecast of the scope of works required. The works required include the replacement of 330 kV disconnectors, post insulators including HV conductors, voltage transformers, wave traps, transformer bushings, and the reshaping of 330 kV conductors to reduce terminal loading forces.

[16] Greater Sydney Commission, *Greater Sydney Region Plan*, March 2018, p 16.

Anticipated expenditure is expected to be $51 million, with completion expected in 2026/27 in order to ensure ongoing compliance with NER Clause S5.2.8 and avoid the damage to the transmission and generator equipment and reduce the safety risks.

Table 6-15 Manage increased fault levels in Southern NSW contingent project

Project details	Particulars
Current expected timing	2026/27
Status	Preliminary activities
Estimated total Augex	$51 million
Estimated Augex in the 2023-28 regulatory period	$51 million

7. Forecasting method, inputs, models and assumptions

7.1. Introduction

The purpose of this chapter is to explain our forecasting methodology, the inputs to that methodology and the forecasting assumptions that are reflected in our Augex forecasts. We provide additional detail in relation to key demand drivers over the upcoming regulatory period and the need for system services in chapter 8.

Our investment framework provides that we only undertake investments that deliver demonstrable customer benefit, or are required to meet a statutory obligation. These benefits are assessed through the risk and investment analysis process, where the impacts of our proposed investments are given a defensible monetary value to enable the relative benefits and costs to be compared.

Under this framework, expenditure is only supported when the present value of the costs is less than the present value of the economic benefits by avoiding the risk that would exist without investment, or by providing economic benefits in excess of the costs of the investment.

Some investments are required to fulfil a statutory or regulatory obligation, such as meeting obligations set out in the National Electricity Rules (NER). In these cases, technical justification becomes the main arbiter as to whether an investment is required, and we have robust technical planning and sophisticated analysis capabilities to ensure that such investments are undertaken. Notwithstanding this, these investments are also subject to tests of economic efficiency, with any proposed solution to address a need being the least-lifecycle cost and most technically effective solution, as attested through our Prescribed Capital Investment Governance process.

7.2. Forecasting method

7.2.1. Energy and Maximum demand forecasting

Underlying consumer demand for electricity is traditionally understood to be driven by population and economic growth, energy prices, and by weather. In the past decade however, a coincidence of energy efficiency, take up of DER (particularly household solar PV) and rising electricity prices have acted to moderate demand. In preparing the NSW region demand forecasts, we have therefore considered the combined impacts of traditional drivers, changes in consumer behaviour, energy efficiency and DER on the transmission network demand.

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

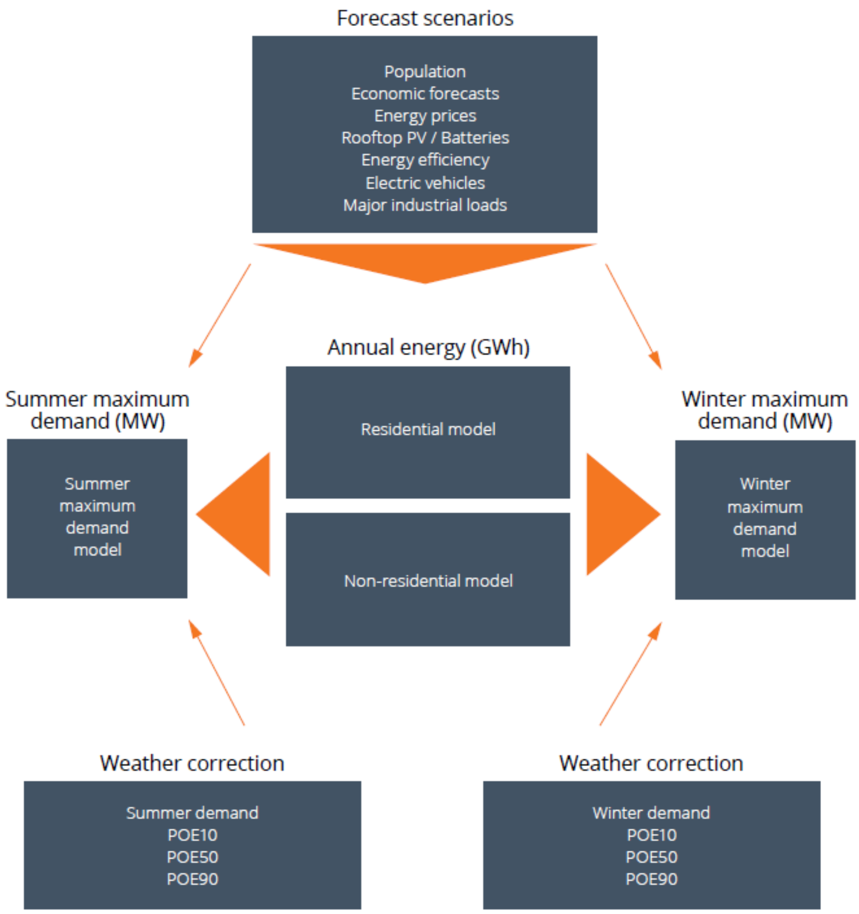
- econometric modelling of the impacts of population, price, economic growth, weather and other drivers of underlying consumer behaviour – undertaken independently by us with help from GHD;
- weather correction of historical electricity maximum demands and the calculation of probability of exceedance levels – undertaken independently by us with help from GHD;
- regional demographic and economic forecast scenarios – provided by BIS Oxford Economics;[17]

[17] BIS Oxford Economics, Economic and Dwelling Forecasts to 2040 - NSW and ACT, Final, April 2021.

- projections of future energy price paths – undertaken by Jacobs;[18]
- assessment of recent energy efficiency policies and standards, and quantification of the energy savings impacts – undertaken by Energy Efficient Strategies;[19]
- modelling of rooftop PV installation and generation, and distributed battery storage – undertaken by Jacobs;[20] and
- projections of the take-up of externally charging electric vehicles – undertaken by Energeia.[21]

Figure 7-1 presents these components schematically with their interactions.

Figure 7-1 Demand forecast modelling schema



Econometric modelling was used to estimate the independent impacts of population, electricity price, economic growth and weather on annual native electrical energy. Native energy is composed of electricity consumed by residential and major industrial customers. However, our energy modelling for 2021 includes overall analysis of total energy use for eight different end-use sectors. Previously we only modelled

[18] Jacobs, Retail Price Projections for NSW, Final Report, March 2021.

[19] Energy Efficient Strategies, Projected Impacts of Energy Efficiency Programs, Final Report, May 2021.

[20] Jacobs, Rooftop PV and Battery Scenarios, April-May 2021.

[21] Energeia, Electric Vehicles Modelling March 2021, Report to Transgrid.

electricity consumed by residential and the generic non-residential sectors. The grid electricity share of each sector's energy use is derived from underlying trend shifts, changes in relative energy prices and the take-up of PV self-generation.

We estimated the effect of major drivers of energy consumption by constructing empirical models of energy use for the residential sector as well as seven ANZSIC[22]-derived industry sectors, including:

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

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

The primary source of historical energy data was Australian Energy Statistics[23]. This was supplemented by estimates of the out-of-trend impacts of energy efficiency measures and small-scale rooftop PV generation. The grid-supplied electricity historical data was extracted from TUOS as a sent out measure by us.

In all, eight separate auto-regressive distributed lag (ARDL[24]) models were designed to take account of the major drivers of energy use - population, price and income in the long-run, and temperature in the short-run. The models used projected future values for population, income and prices, and assumptions about mean temperature trends, to forecast total energy consumption for each sector.

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

Maximum Demand

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

[22] Australian and New Zealand Standard Industry Classification, https://www.abs.gov.au/ausstats/abs@.nsf/0/20C5B5A4F46DF95BCA25711F00146D75?opendocument.

[23] Australian Energy Statistics, Department of the Environment and Energy, Australian Energy Statistics, Table F, September 2020

[24] An ARDL model is a linear equation which provides for inclusion of one or more lagged dependent and independent variables. In a long run time series relationship where the equation errors are shown to have constant mean and variance, regardless of the sample chosen, are said to be cointegrated. Adoption of an ARDL technique in the case of cointegrated variables can be shown to have an equivalent error-correction equation form.

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

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

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

Our projections of summer and winter maximum demand are based on historical POE10, POE50 and POE90 underlying maximum demands, including estimated above-trend energy efficiency. This removes the year-to-year variability due to weather-sensitivity and the impact of accelerated energy efficiency and DER.

The forecasts of underlying maximum demand are prepared as follows:

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

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

Table 7-1: Summary of key assumptions for annual energy and maximum demand forecast

Parameter or variable	Assumption
Modelling Inputs	
Population growth (average 2021/22 to 2030/31)	1.1 % pa
Real household disposable income (average 2021/22 to 2030/31)	2.0 % pa
Economic growth GSP (average 2021/22 to 2030/31)	2.3 % pa
Real residential electricity price (average 2021/22 to 2030/31)	0.8 % pa
Real non-residential electricity price (average 2021/22 to 2030/31)	0.7 % pa
Real price of gas and other fuels (average 2021/22 to 2030/31)	3.2 % pa
Average temperature increase (every 10 years)	0.5 ^{o}C
Modelling Elasticities/Temperature Sensitivities	
Household disposable income (HDI) elasticity (residential)	0.71 %
Retail electricity price elasticity (residential)	-0.55 %
Average daily temperature sensitivity (summer)	395 MW/^{o}C
Average daily temperature sensitivity (winter)	-216 MW/^{o}C

7.2.2. Augex forecasting

Augex is forecast by using our network planning criteria to calculate the value of risk associated with the thermal and stability constraints that materialise through high demand and generation power flows within our network, comparing this risk against the cost of augmentation options to alleviate the risk. Our network planning criteria embraces all of the requirements set out in the NER and the NSW Reliability Standard, and is consistent with the network planning practices adopted by other TNSPs, including AEMO. Our method of assessment for the prudency of our Augex forecast is consistent with the AER's RIT-T Application Guidelines[25].

Our network planning process is an integral part of our certified ISO 55001 Asset Management System. In demonstrating this alignment, we seek to ensure we are forecasting according to good electricity industry practice with a program of works that is based on prudent and efficient expenditure decisions, in a consistent manner that provides greater levels of transparency for stakeholders.

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

[25] https://www.aer.gov.au/system/files/AER%20-%20Regulatory%20investment%20test%20for%20transmission%20application%20guidelines%20-%2025%20August%202020.pdf

- avoiding the large cost to the community of widespread shortages of supply
- providing flexibility in the choice of economical generating patterns
- allowing reduced maintenance costs, and
- minimising electrical losses.

Our Augex forecasting method includes the following steps:

- identifying the constraints (existing or emerging) within the transmission system and their drivers which may trigger the need for investment. This is undertaken using demand forecasting and power system operational measurements and simulation, comparing these operating conditions against our network planning criteria
- calculating the forecast expected risk or lost opportunity cost associated with the constraint, taking into account the probability and consequence of the risk materialising, which could be:
  - a breach of our compliance obligations (i.e., service standard, including mandated reliability or stability requirements)
  - EUE in the case of unplanned interruptions (i.e., reliability)
  - an inability to connect a new customer load (i.e., spot load), and/or
  - constraining generation which leads to higher energy costs (i.e., economic benefits)
- identifying a set of credible options to address the identified need which are (in recognition that there may be feasible non-network alternatives) a set of network augmentation solutions which are technical feasible to reduce or eliminate the risk at least cost, and
- comparing the avoided risk cost against the cost of the credible options to augment the network using an economic cost-benefit evaluation.

This evaluates the lifecycle cost of the reasonable network (and non-network) options that are available to address the risk and enables the selection of the option that delivers the highest net value to stakeholders.

The process is repeated for each investment need, selecting those projects that deliver the highest value to ultimately form an augmentation program that maintains current levels of network risk. We adjust scope or timing of projects to incorporate potential overlap with other capital expenditures and constraints from business planning processes to ensure deliverability and optimised outcomes at the portfolio level.

Table 7-2: Summary of forecasting methodologies by driver

Driver	Forecasting Methodology
Demand Driven	EUE multiplied by VCR
Minimum Demand	Least cost
Economic Benefits	Expected volume of energy impacted multiplied by changes in wholesale electricity prices and/or EUE multiplied by VCR
Compliance	Least cost

7.3. Risk and benefit types

Economic justification of Augex expenditure to address an identified need is supported by risk monetised benefit streams by applying probabilistic planning principles. This allows the costs of the projects to be assessed against the value of the avoided risks or benefits. The major quantified risks we apply for Augex justifications include operating constraints that materialise as:

- **Reliability risk** – This refers to the system reliability and security consequence to the network of a materialising network constraint or supply-demand imbalance. The monetary value takes into account the amount of expected load-at-risk and duration of loss of supply (MWh) due to the constraint being applied and any subsequent actions, and a Value of Customer Reliability (VCR) per MWh of lost load for the customer type impacted
- **Market risk** – This refers to the impact that constraining generation has on wholesale energy prices as a result of a network constraint. The monetary value takes into account the expected volume of energy (MWh) impacted by increases in the marginal price of electricity as a result of AEMO needing to reschedule generation dispatch or the inability for lower cost generation to connect to the system because of a network constraint.
- **Market benefits** – This refers to the specific categories of market benefit under the RIT-T, including:
    - changes in fuel consumption in the NEM arising through different patterns of generation dispatch
    - changes in costs for parties, other than the RIT-T proponents
    - differences in unrelated transmission investment
    - changes in involuntary load curtailment
    - changes in network losses, and
    - competition benefits.

7.4. Risk and benefit models

Our risk-cost assessment utilises probabilistic reliability planning techniques which is undertaken internally, and market modelling which is undertaken by externally-sourced specialist consultants.

The planning of the main system must take into account the risk of forced outages of a transmission element coinciding with adverse conditions of load and generation dispatch. In our reliability risk modelling, we consider failure probabilities and the capabilities of each asset involved in a constraint, the relevant repair and restoration times of each, available pre-and post-contingency actions, and the range and likelihood of the power system demand and generation conditions.

The key benefit of Augex projects in subsystem is the reduction in the amount of EUE. The EUE has been determined based on the network topology, equipment availability, load level and system capacity.

The risk-costs and benefit associated with the unserved energy is valued at the VCR released in AER's VCR review in December 2019. This provides expected quantified risks which are then used in economic evaluation assessments to justify our Augex forecast.

We utilise an integrated, data-driven risk modelling approach for Augex. The risks has been calculated by tallying selected critical contingencies that result in the inability of the network to service the required load. This calculation has been done by using a historical yearly load profile (half hourly load intervals), then scaled by the maximum demand forecast to evaluate future load. For each critical contingency, the unserved energy has been determined based on the supply capability, equipment failure probability and load level.

The optimal project timing is determined as the year when the annual benefit exceed the annualised project cost based on the asset service life and discount rate.

7.5. Key assumptions

Clause SA6.1.1(4) of the Rules requires us to list the key assumptions that underpin our capex forecast. The key assumptions applying across the Augex forecasts are summarised in Chapter 8 of the Revenue Proposal document and replicated in the following table.

Table 7-3: Summary of key assumptions for Augex forecast

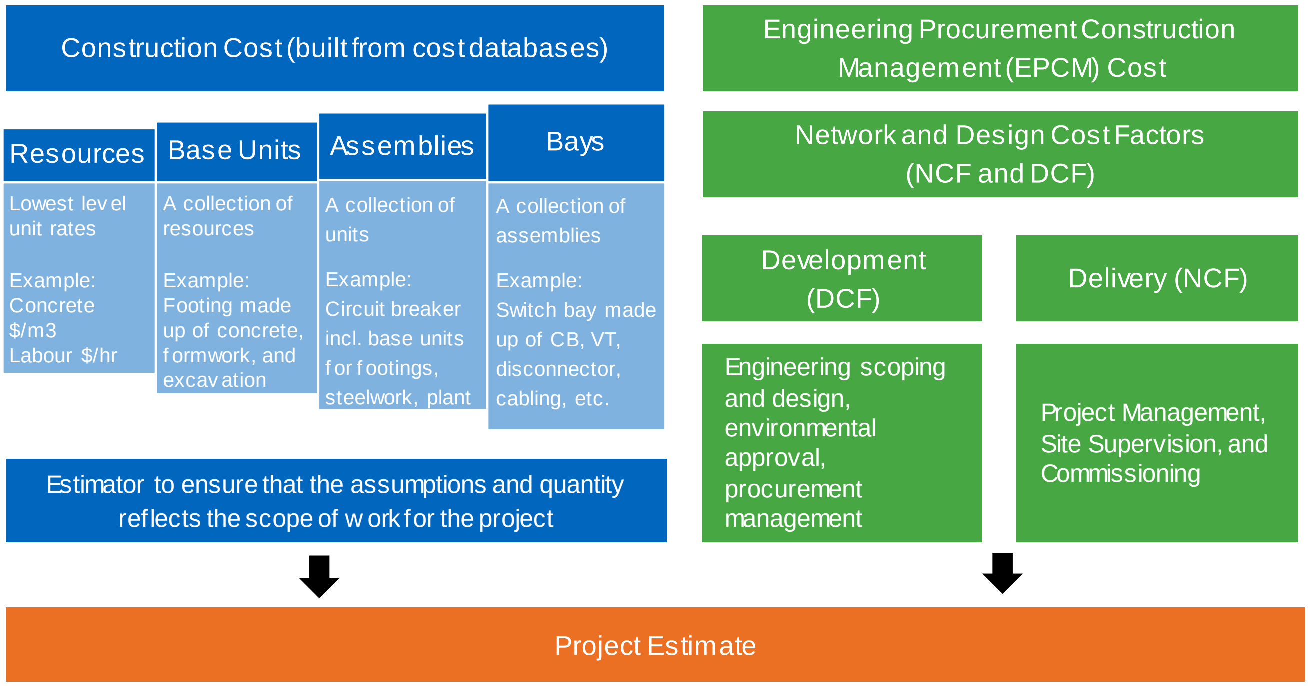
Assumption	Description
Legislative & regulatory obligations	Our capex forecasts are based on our current legislative and regulatory obligations and our licence requirements
Network reliability	Our capex forecast will maintain, but not improve, service outcomes consistent with clause 6A.6.7(a)(3)(iii) of the NER
Demand forecasts	Our forecasts are required to meet DNSPs' connection point demand forecasts (published in our TAPR) reconciled to AEMO's forecasts.
Value of customer reliability (VCR)	Our capex forecasts reflect AER's VCRs, which represents the monetary value different types of customers place on having access to a reliable electricity supply. The VCR is a key input into how we determine when to replace assets on our network.
Unit rates and project costs	The unit rates and project costs that we have applied in developing our capex forecasts are representative of the costs that will be incurred in the next regulatory period.
Cost allocation and capitalisation	Our capex forecasts reflect our capitalisation policy and our CAM, which provides an appropriate basis for attributing and allocating costs to, and between, our prescribed transmission and other services.
Cost escalations	The cost escalations that we have applied in developing our capex forecasts are representative of the increased costs that we will incur in the next period
Inflation	The inflation that we have applied in developing our capex forecasts is representative of the inflation-related costs that we will incur in the next period and is consistent with the AER-preferred inflation forecasting method
Cost pass throughs and contingent projects	The AER will approve our nominated pass through events and contingent projects

7.6. Unit costs

Our Augex forecast is comprised of non-unitised projects which are individually costed. All our capital expenditure for non-unitised works is estimated using our MTWO cost estimation database which is updated on an annual basis. The outputs of this database feed directly into our 2023-28 Capital Expenditure Model which is included in our Regulatory Proposal.

Non-unitised project tailored cost estimates are developed for augmentation work because it has a high level of complexity, which means that it cannot be costed upfront based purely on unitised rates. We perform an engineering assessment to generate a detailed scope of works which is compiled with itemised cost elements using costs sourced from our MTWO cost estimating system. This system utilises historical average costs, updated by the costs of the most recently implemented project with similar scope. The estimates incorporate design and network cost factors to determine the internal labour support requirements and construction costs as illustrated in Figure 7-2.

Figure 7-2 Non-unitised project cost estimation



Key sources of price data used for our non-unitised estimates include:

- Primary plant – current Period orders and other procurement strategies
- Other plant, equipment, materials – Ellipse ERP system for stock lined items, available tender/quote information, direct enquiries to manufacturers and Rawlinsons (Australian Construction Handbook)
- Construction Costs – All awarded contracts within the previous twelve months
- Labour rates – Updated with latest labour rates, and
- Design and network cost factors - percentages are determined based on analysis of actual costs from similar past projects.

7.7. Cost escalation

The costs we incur in delivering transmission services do not always increase in line with the basket of goods and services used by the Australian Bureau of Statistics (ABS) to calculate the consumer price index (CPI).

Therefore, in order to ensure that we are compensated for appropriate real cost increases that we will incur in acquiring the inputs necessary to provide services, we have engaged BIS Oxford Economics to forecast real increases in the cost of labour costs that we expect to incur during the 2023-2028 regulatory period.

Although we consider that real costs increases for materials are likely to grow faster than inflation over the 2023–28 period, we have not presently included any real materials cost escalation.

We have applied the labour cost escalators to our capex forecasts using appropriate weightings based on an estimated use of internal labour services to deliver work programs. While our Replacement capex forecasts include the impact of cost escalation, our analysis in preparing the forecasts is conducted without the effect of cost escalation.

For example, the detailed analysis in the OFS is conducted exclusive of cost escalators for the forthcoming regulatory period. To assist the AER, however, each of the capex overview papers includes a reconciliation table showing the escalated forecasts. The table below shows the aggregate impact of the cost escalators on our Replacement Capex forecast for the forthcoming regulatory period.

Table 7-4: Impact of labour and materials escalation ($Million, Real 2022-23)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Total un-escalated Augex	**48.5**	**64.3**	**37.4**	**33.9**	**69.0**	253.1
Escalation for material and labour	**(0.0)**	**0.1**	**0.1**	**0.1**	**0.3**	0.5
Total escalated Augex	48.5	64.3	37.5	34.0	69.2	253.6

Further details regarding our cost escalators are provided in the supporting document titled “BIS Oxford Economics - Labour Cost Escalation Forecast to 2027-28”.

7.8. Overheads

Overhead activities, such as network planning, are needed to support Augex. The costs of those activities are capitalised in accordance with our Capitalisation Policy[26] and relevant accounting standards, including AASB 116.

Capitalised overheads are split between network and corporate overheads, consistent with the AER’s RIN definitions. We have forecast our overhead costs using the AER’s default approach based on:

- 75 per cent of capitalised overheads are fixed based on the most recent available year of actual capex (i.e. 2021-22), and
- 25 per cent of capitalised overheads vary with direct capex.[27]

The capitalised overhead forecast related to Augex is set out below. As shown in the table, changes to total escalated Augex from one year to the next affects the level of capitalised overheads allocated to Augex.

[26] Expenditure Capitalisation Procedure, Transgrid, 2018.

[27] This approach was adopted by the AER in its April 2021 decisions for the Victorian electricity distribution networks.

Table 7-5: Addition of capitalised overheads ($Million, Real 2022-23)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Total escalated Augex	**48.5**	**64.3**	**37.5**	**34.0**	**69.2**	253.6
Capitalised network overheads	**6.8**	**7.7**	**4.9**	**4.9**	**8.5**	32.7
Capitalised corporate overheads	**0.9**	**1.1**	**0.7**	**0.7**	**1.2**	4.6
Total escalated Augex with overheads	56.2	73.1	43.1	39.6	78.9	291.0

Capitalised overheads are forecast within our "2023-28 Capital Expenditure Model".

7.9. Capex-opex substitution

Opex substitution opportunities are assessed at the individual project and program justification level, rather than at the portfolio level. This is because it is challenging to demonstrate opex-capex trade-offs for broad-based solutions, without considering the individual projects' costs and benefits.

We regularly screens projects for opex alternatives that have the potential to substitute capital costs – through either their deferral in the short-term or provide capital reductions over the long-term. These projects can are categorised as load-driven (demand management projects).

We are presently assessing the efficiency of demand management and network support (opex) solutions for a number of projects, which may have a non-network option component that forms part of the preferred solution and therefore affects our opex forecast. However, it is premature to definitively include these costs in our forecasts as they are undergoing the RIT-T process, which will test whether additional non-network solutions can cost-effectively reduce or defer capital costs. Notwithstanding other load-driven opportunities that may arise over the next regulatory control period, they are:

- Maintaining a reliable supply to Broken Hill (PADR)
- Improving stability in south-western NSW (PADR)
- Managing Risk on Transmission Line 86 (PSCR)
- Maintaining reliable supply to Bathurst, Orange and Parkes areas (PSCR), and
- Maintaining reliable supply to the North West Slopes area (PSCR).

Our demand management forecast is therefore dependent on the outcome of these RIT-Ts. If non-network options form part of the preferred solution once these RIT-Ts are complete, we will include these opex costs in our revised proposal submission. If these, or other, RIT-Ts are completed after the final regulatory determination and the preferred option includes a non-network solution, we will recover the opex costs associated this these solutions via the network support pass through provisions in the NER.

7.10. Portfolio optimisation

The portfolio review process considered both Augex and Repex and assessed the following as part of optimisation:

- Deliverability / resource levelling was reviewed by considering the timing of individual projects and their associated S-curve within the project estimates.
- Considered project scope interactions across both Repex and Augex projects and programs. Direct scope overlaps were identified across the needs including:
  - Replacement of an auxiliary transformer at Murray due to condition that was proposed under Repex and also under an Augex need to maintain safety and quality of supply at Khancoban. The replacement was included under the Repex portfolio and the Augex need subsequently not further progressed.
  - We also scope overlaps between the Repex programmes and the Manage increased fault levels in Southern NSW contingent project, and have removed in consideration of the likelihood of the contingent project proceeding during the upcoming regulatory period. These include:
    - Disconnector units proposed to be replaced under Repex programmes also included in the scope of the contingent project at Murray and Upper Tumut.
    - CVT's proposed to be replaced under Repex programmes also included in the scope of the contingent project at Wagga and Upper Tumut.
    - It should be noted that the contingent project scope would have required the replacement of the transformer bushings at Murray. Given that these power transformer replacements have been included under the Repex transformer renewal programme, these have been removed from the scope from the contingent project accordingly.
  - Portfolio adjustments have been made to so to not include the expenditure associated with the direct scope overlaps.

7.11. Validation

7.11.1. Maximum demand forecast validation

We reconcile our NSW regional maximum demand forecast with the regional forecasts prepared by AEMO, and against the aggregated Bulk Supply Point (BSP) maximum demand forecasts provided to us by the DNSPs. The following sections describe the details of the comparisons.

7.11.1.1. Comparison with AEMO's forecasts

As presented in our 2021 TAPR, we have compared our forecasts with AEMO's top down forecasts for the NSW region that was published in August 2020 as an update to the 2020 Electricity Statement of Opportunities (ESOO). This section compares our 2021 top down maximum demand forecast and AEMO's maximum demand forecast update for the NSW region.

Both demand forecasts are presented on a 'native as-generated' basis. The details of AEMO's demand forecast is provided on the AEMO website.[28]

In order to compare the our forecasts and AEMO summer and winter maximum demand forecasts, we combined AEMO's 'native sent out' neutral 50% POE forecast and AEMO's 'auxiliary load' neutral 50%

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

POE forecast. This summated AEMO forecast is compared to our ‘as-generated’ medium 50% POE forecast and is shown in the following figures.

Figure 7-3 and Figure 7-4 show a comparison between our 2021 summer and winter maximum demand medium scenario forecasts and AEMO’s central scenario (summer and winter) maximum demand forecasts in its 2020 ESOO. Both forecasts are expressed on a “native as generated basis” and hence can be directly compared.

Figure 7-3: Transgrid’s 2021 vs AEMO’s ESOO 2020 summer maximum demand forecast for NSW region

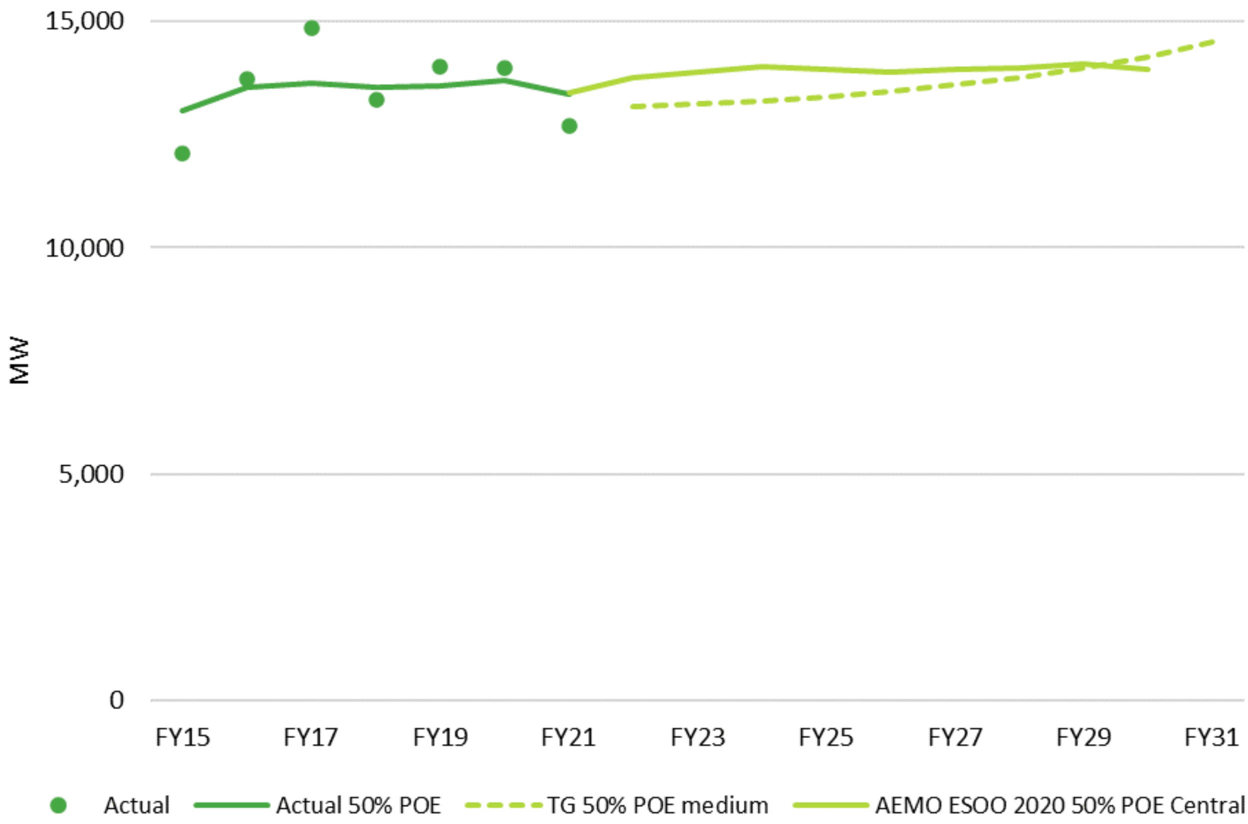
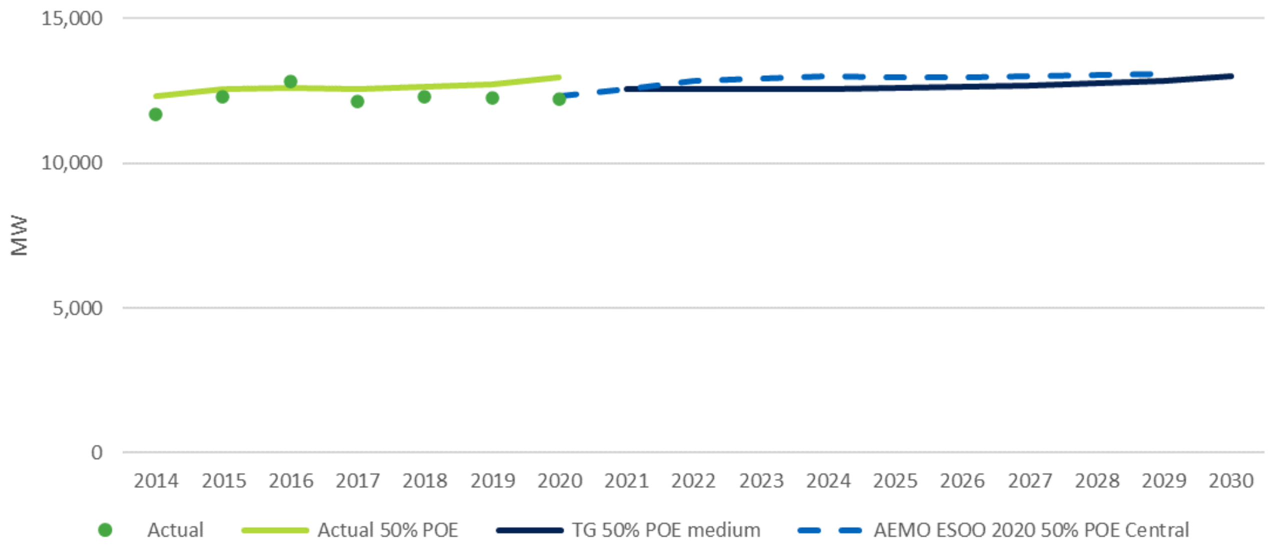


Figure 7-4: Transgrid's 2021 vs AEMO's ESOO 2020 winter demand forecast for NSW region



7.11.1.2. Reconciling with DNSP forecasts

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

- use 50% POE forecasts where they are available, and where they are not available, assume that individual BSP projections are likely to have been based on enough historical data to converge towards an approximate 50% POE forecast
- diversify individual BSP forecasts to allow for the time diversity observed between historical local seasonal maximum demand and NSW maximum demand
- add forecast aggregate directly-connected industrial loads not included in the BSP forecasts, and
- incorporate transmission network losses and power station auxiliary loads, derived from recent historical observations, to express the forecasts in the same 'as-generated' basis.

Figure 7-5 Comparison of our NSW summer region maximum demand forecast against aggregated BSP forecast

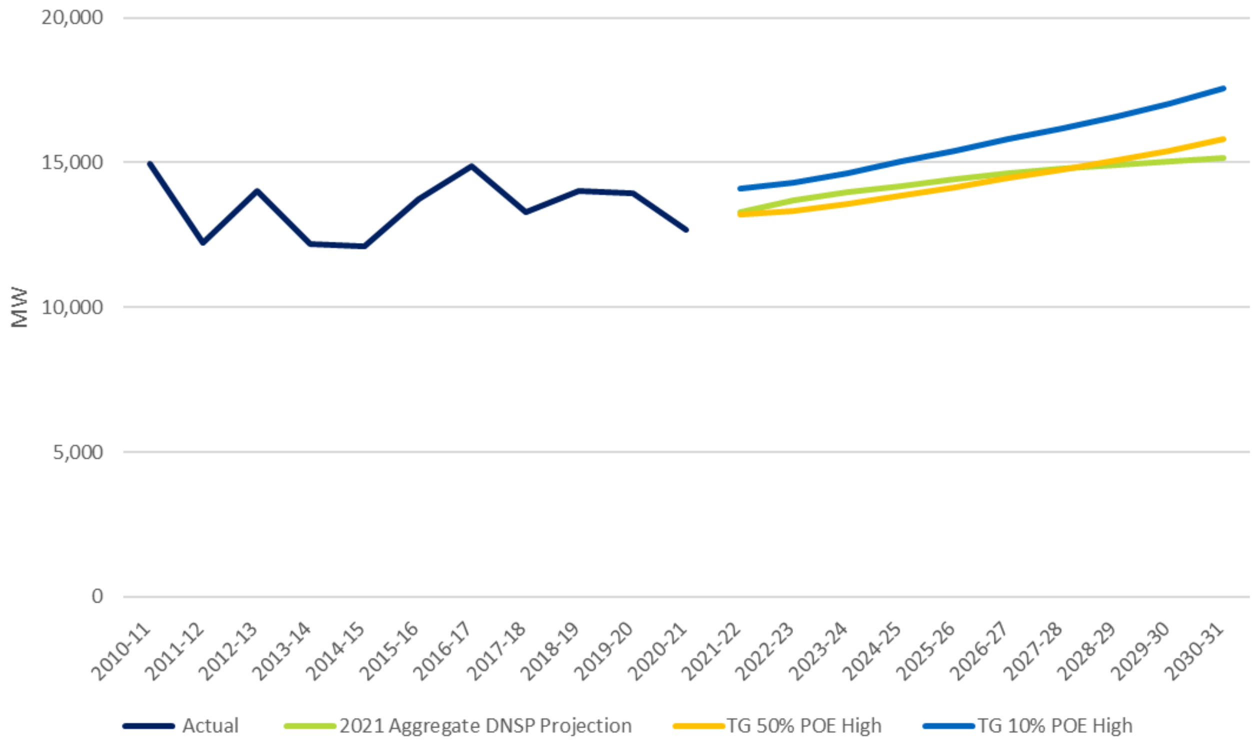
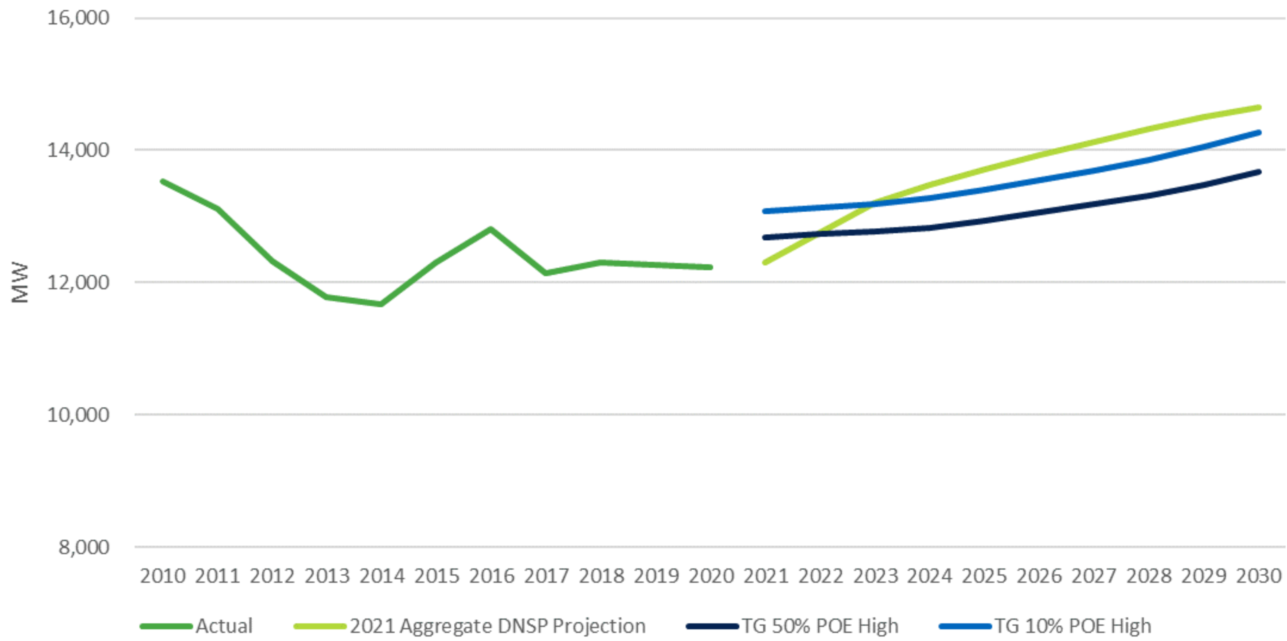


Figure 7-6 Comparison of our NSW winter region maximum demand forecast against aggregated BSP forecast



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

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

7.11.2. Internal validation

Once all of the augmentation investment needs have been evaluated, the Augex portfolio is assembled in order of the value of risk mitigation delivered by the investment and reviewed on a top-down basis to ensure alignment with the total investment requirements and associated targeted outcomes for consumers. At this point, total augmentation expenditure can be optimised by removing or re-scoping projects to maximise stakeholder value within a top-down expenditure constraint. This ensures that we can manage our future investment to moderate the impact of any step changes that Augex requirements may have on total expenditure.

We have an established process to review and 'challenge' the forecast expenditure portfolio to ensure that it is aligned to strategic objectives and customer feedback with regards to cost and service levels. Our investment management team does this by reconciling our bottom-up build of Augex forecasts with a number of top-down reconciliation methods including:

- **Historical expenditure trending** – Our Augex program for the next regulatory period is increasing compared with the current and previous regulatory period, when contingent projects are not considered. The relative increase in our base Augex is being driven by load growth, predominately from industrial spot load connections, in parts of the network which are already very close to their supply capacity and stability limits. We have also identified opportunities to deliver market benefits by reducing network constraints in areas where renewable generators have recently connected to the network. For these reasons, our augmentation plan will vary from historical annual expenditure depending on prevailing demand growth forecast and network conditions at the time.
- **Avoided risk profile** - We also have a view of the avoided risk at the Portfolio level to quantify the overall avoided risk benefit which is being provided to customers within the forecast expenditure envelope. All risks we quantify are appropriately moderated to reflect the safety and performance outcomes that are expected to be experienced by our customers, to maintain safety and performance levels, and
- **Sensitivity and Scenario** - Sensitivity of the risk output is checked by developing suitable statistical distributions of key inputs such as, value of customer reliability, load forecast, cost-of-capital, probability of failure, and likelihood of consequence. These inputs are considered important as they predominantly drive the overall risk output and are assessed in each Options Evaluations Report business case. We also have regard to AEMO's ISP scenarios and their assumptions.

This process ensures that our proposed program is well scrutinised and aligned to Board objectives and customer outcomes, within the constraints of our statutory obligations for network safety and reliability.

7.11.3. External validation

We engage external independent consultants to verify and validate our processes and forecasts:

- **Completeness against NER and jurisdictional planning requirements** - We undertake annual compliance checks of the IPART reliability standard through Cutler Merz, using inputs of our 50%POE demand forecast along with any changes to the network configuration. A report is submitted to IPARPT by end of August annually demonstrating this compliance.

- **Good Practice Benchmarking** - We undertake annual benchmarking of our cost estimation. In 2019, two estimates were benchmarked by the Quantity Surveying company, Vscope. The results concluded that there is close alignment for the overall cost for both projects estimated with all improvement opportunities identified having been addressed. We also engaged Jacobs in October 2019 to undertake an independent verification of our Capex Estimating Database. Jacobs concluded "*that the Capex Database process and methods employed were robust. As with all estimation, the critical factor in ensuring a correct outcome is correctly defining scope. It was found that if a project is defined and scoped correctly, the outcomes were reasonably within market expectations and resulted in adequate pricing.*"
- **Independent Consultant Review** - GHD was engaged to review the reasonableness of inputs, assumptions and forecast outcomes including the demand forecasting methodologies used by DNSPs for the BSP forecasts. The review included an assessment of our forecasts against the 2020 AEMO connection point forecasts. GHD were able to reconcile the differences, if any existed, between our demand forecasts and AEMO's forecasts finding that our forecast represent a realistic expectation of future demand.

7.12. Addressing uncertainty in investment requirements

Uncertainty is inherent in any forecast and our Augex forecasts are no different. To avoid adding additional risk-costs to our projected expenditure requirements, our forecasting approach addresses uncertainty through several mechanisms to ensure that we do not overestimate our expenditure requirements. These include:

- using a 50th percentile demand forecast as the primary input into the network augmentation planning process. This is supported by evaluation of the portfolio under low and high demand scenarios to evaluate the extent to which the total capital expenditure is sensitive to the range of demand outcomes
- evaluating a range of future generation and load scenarios consistent with AEMO's 2020 ISP to include only the probability-weighted expenditure for the proposed demand driven investments. This means that the expenditure included for most augmentation projects is reduced to reflect that the investment may not be required under all of the planning scenarios
- establishing a suite of contingent projects to ensure that the total capital expenditure allowance is not overstated by projects which are dependent on actions taken by external parties. Instead, contingent projects are excluded from the capex allowance but can be progressed during the next period when a suite of pre-defined triggers are satisfied
- using recent market costs in our cost estimation database to monitor and minimise cost variation over the life of projects. These are supported by independently forecast labour and materials price escalation over the next period (where they materially differ from the CPI forecast)
- conducting sensitivity analysis on the business case inputs for augmentation investments, to test the sensitivity of proposed investment options and associated expenditure requirements to reasonable changes in input parameters
- consideration of the extent to which the project justification relies on a historically low regulatory WACC for a discount rate by applying a higher 'commercial' discount rate in the analysis that is more reflective of historical financing costs. This means that most investment satisfies a more demanding cost-benefit criteria, with investments that fall between the regulatory and commercial discount rates subject to further scrutiny

- recognising the flexibility available to manage risks within the period to respond to unforeseen needs by re-evaluating priorities in response to more up-to-date generation and network loading information. This results in reallocating investment allowances from planned projects that have not proceeded to other projects as priorities change, followed by a review of whether any risks can be managed in the short term to accommodate more critical investment needs, and
- the uncertainty provisions in the regulatory framework such as periodically resetting revenue to an efficient level, the allowance for a modest overspend before triggering an ex-post review and the option to reopen a decision in-period if necessary, provide broader measures for managing uncertainty.

This process ensures that forecasting uncertainty is managed for the direct benefit of customers and stakeholders.

8. External demand and system services drivers

8.1. Increasing maximum demand and reducing minimum demand, spot load and new connections

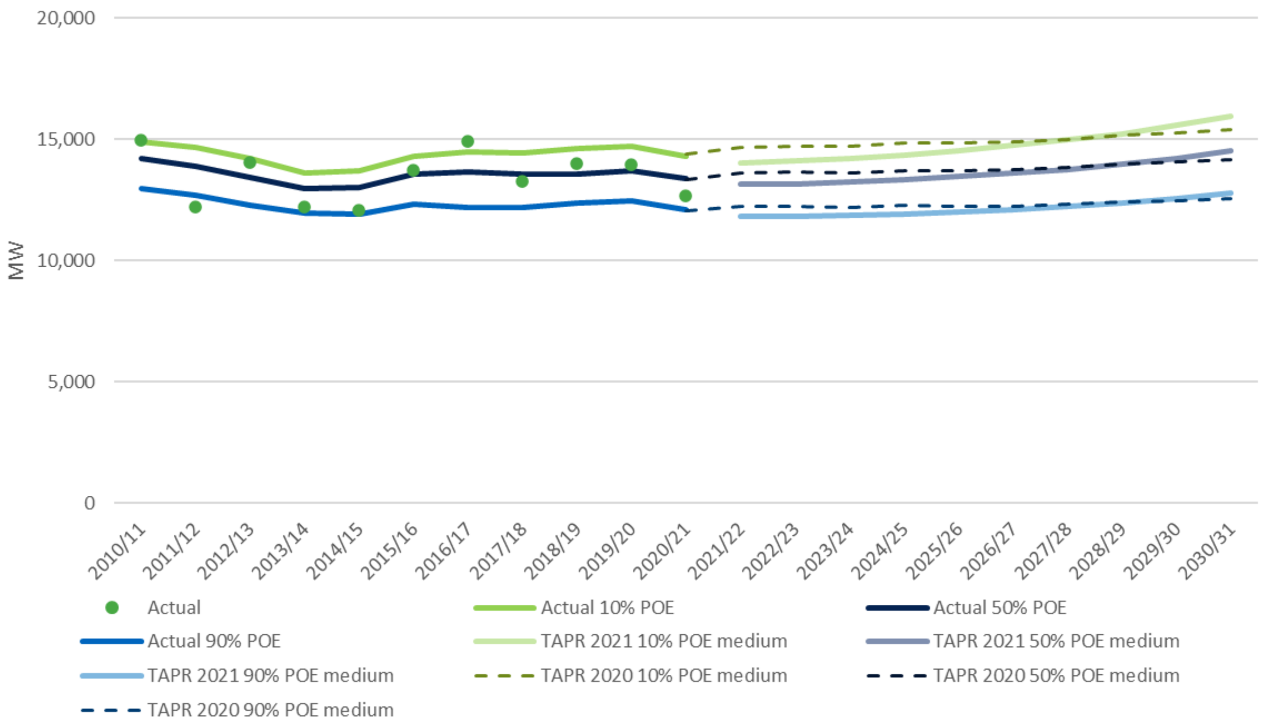
The next decade will see electricity demand grow due to industrial and mining developments in regional NSW, new transport infrastructure and priority growth areas in Greater Sydney (including Bradfield), and growth in the digital economy. We have identified major network developments and local supply projects in our forecast Augex to address emerging constraints and ensure future demand can be supplied, in line with our Reliability Standard obligations.

8.1.1. Maximum demand growth is still expected

Summer (and to a lesser extent, winter) maximum demand growth is a key driver of our augmentation capital expenditure. NSW regional maximum demand has been steady over the last 10 years due to:

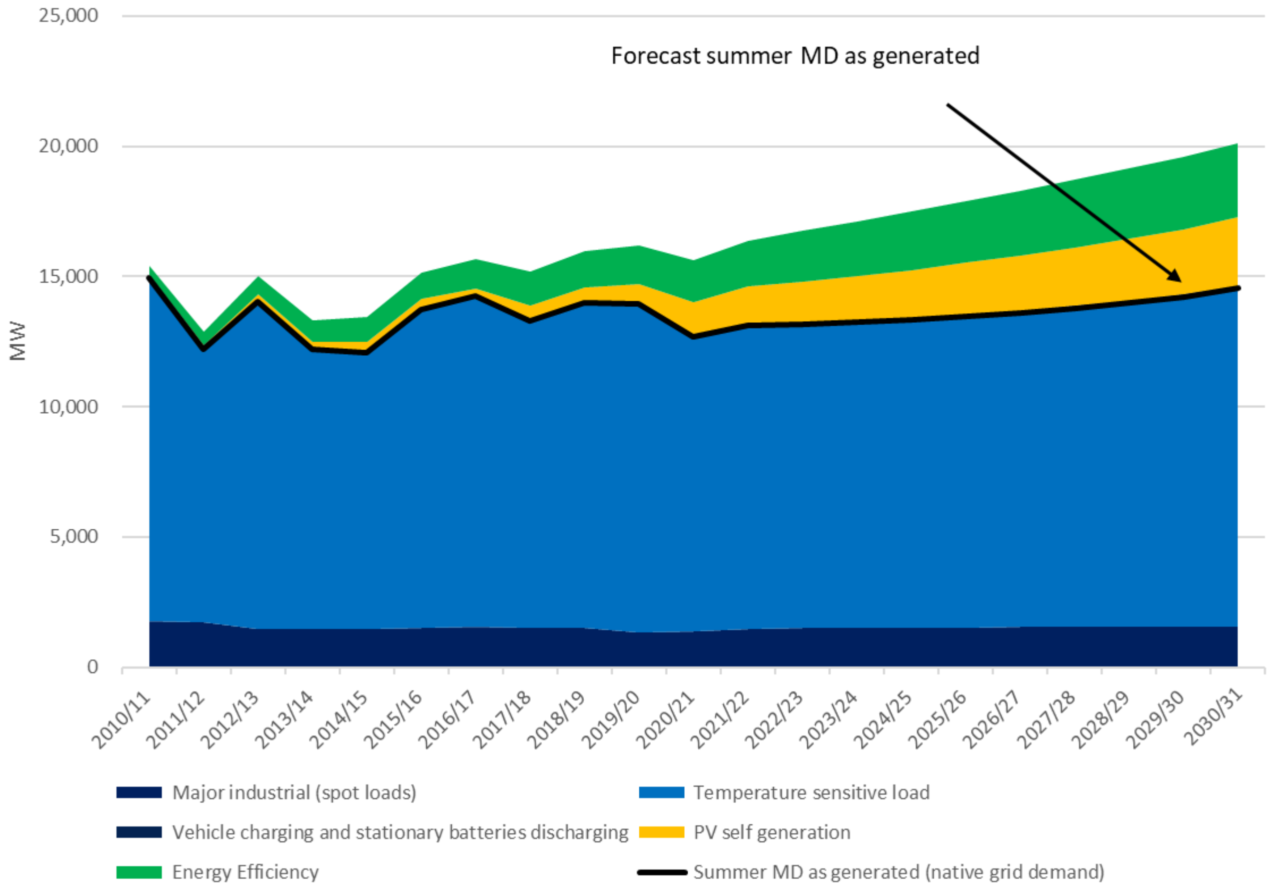
- moderation in underlying growth of energy;
- continued – albeit moderating – growth in air-conditioning use, as air-conditioning ownership gets closer to saturation;
- offsets to growth from energy efficiency, roof-top PV generation and net battery discharging, in combination with the fixed or variable timing of these resources; and
- continued rises in summer average temperatures (as evident from historical summer temperature data) and the effects of global warming. and historical industrial retirements. This is illustrated in Figure 8-1 below.

Figure 8-1 NSW region summer maximum demand - actual, weather-adjusted and forecast



Influences on demand growth going forward include electricity prices, spot loads, longer-term residual COVID impacts, and the uptake of energy efficiency and DER as illustrated below.

Figure 8-2 NSW region summer maximum demand (actual and 50% POE medium forecast)



A significant amount of potential load increase in the grid has been, and will continue to be, offset by accelerated energy efficiency and small-scale rooftop PV take-up. Notwithstanding the offsets due to energy efficiency and rooftop PV, NSW and ACT energy consumption is still forecast to grow at an average rate of 0.8 per cent per annum over the next ten years, after an initial decline due to the immediate effects of COVID-19. Summer maximum demand is expected to grow by around 0.6 per cent per annum and the winter maximum demand by around 0.3 per cent per annum on average over the next ten years.

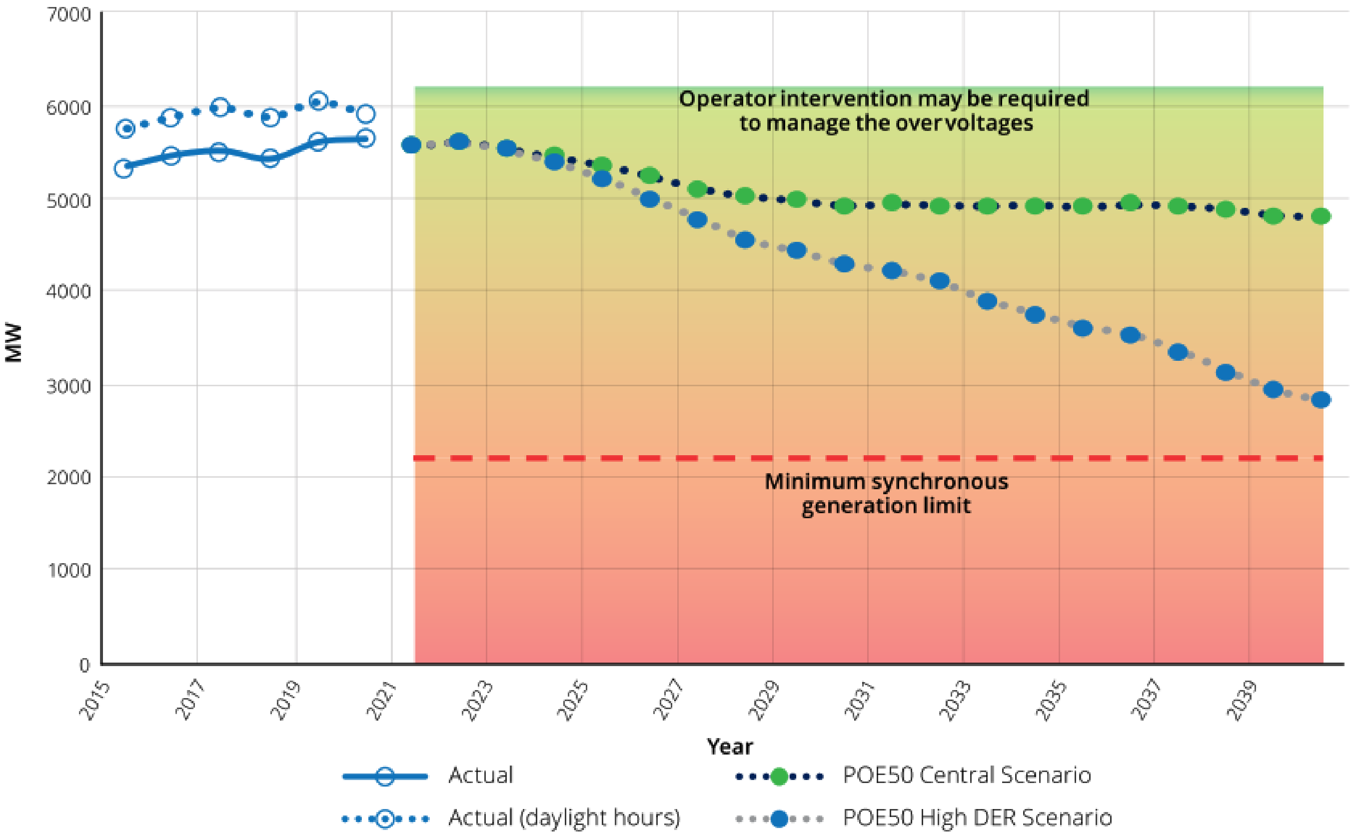
Table 8-1: Actual and forecast NSW region demand growth (percent per annum)

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

8.1.2. Reducing minimum demand will drive the need for investment to maintain voltage stability

Minimum demand is extremely sensitive to forecast growth in distributed PV. Evidence of strong sales and installations in 2020 have strengthened the confidence that consumers continue to look for energy savings through PV installations, and distributed PV forecasts have been revised upwards accordingly. Due to the continued strong uptake of distributed PV projects, forecast minimum operation demand is declining rapidly.

Figure 8-3 Minimum demand outlook for NSW



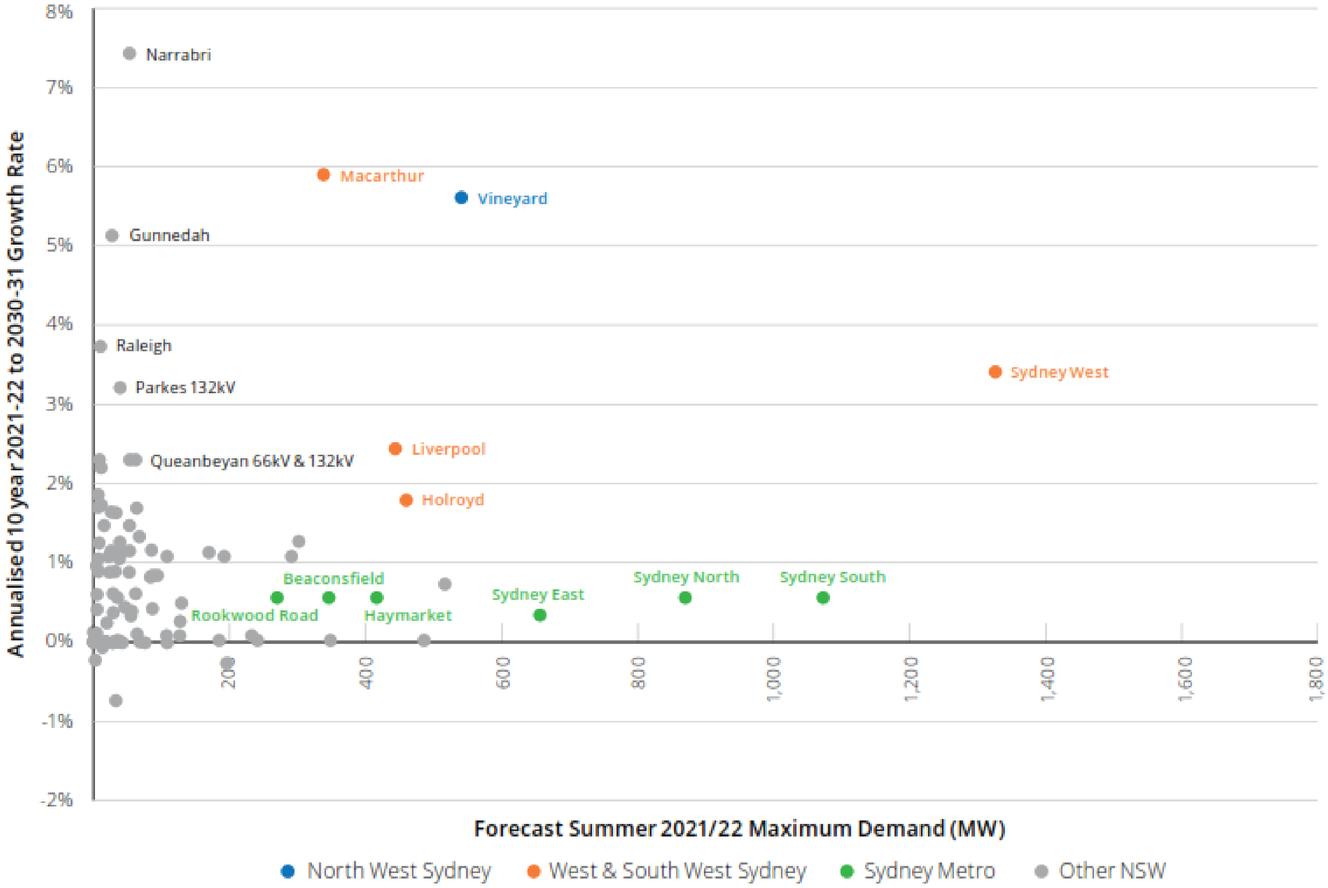
Reductions in minimum demand due to DER will drive the need to undertake a program of installing reactors to ensure continuing voltage stability, at an estimated cost of $4 million.

8.1.3. Pockets of strong maximum demand growth will drive network augmentation

Whilst network-wide maximum demand growth remains low compared to historical growth rates of the early 2000’s, there are pockets of strong maximum demand growth (and some minimum demand issues) that will drive augmentation expenditure in the next regulatory control period. In particular:

- Supply to Sydney West Area
- Supply to Bathurst, Parkes and Orange
- Supply to North West Slopes
- Supply to Far West NSW Network

Figure 8-4 Bulk supply point maximum demand growth rates (percent per annum)



8.1.3.1. Spot load connections are a further driver

The next period's main drivers of demand growth are known spot loads, with several of them in the pipeline. For example, there are five mines proposed in central-western regional NSW, the Narrabri Gas Plant in regional NSW, and industrial precincts totalling greater than 200 MW of new load.

Other drivers are major transport developments, urban growth developments in western Sydney, and some new connections in Canberra totalling more than 300 MW of new load.

Spot loads are the main driver of connection point augmentations with many spot loads appearing in areas of the network that are currently constrained.

Outside of this major project, other projects anticipated over the regulatory period and reflected in our Augex forecast include:

- Supply to Beryl Area, to supply mining loads in the Beryl area
- Supply to Far West NSW, to supply mining load in the Broken Hill area
- Supply to Sydney West Area, to supply Data Centre loads around Sydney West
- Supply to Western Sydney Priority Growth Area, to supply a new precinct in Western Sydney, and
- Augmentation to accommodate anticipated connection of data centres to Evoenergy's network.

8.2. System stability services are also expected to be required

Voltage stability, system strength and inertia requirements are also driving augmentation expenditure into the next period, triggered by the renewable energy transition, reducing the numbers of in-service synchronous generators and changing power flows. This transition is compromising voltage stability, leading to a weakening of system strength and reducing inertia levels in some areas of the network.

Voltage stability

Voltage stability is provided by generators and our network assets such as transformer tap changers, capacitor banks, reactors, Static VAr Compensators (SVCs) and synchronous condensers. Changes in network flows due to the connection of renewable generation and anticipated spot load development, in combination with underlying load growth, are leading to voltage management issues in parts of our network.

In particular, compliance with NER requirements relating to voltage stability is driving the timing of augmentation in the Bathurst Orange Parkes area.

In the south-west NSW transmission network, emerging voltage control issues are materialising due to increased power transfers from renewable generation in the area and an expansion of mining load. At times of high renewable generation near Darlington Point, under-voltages can occur due to the trip of the Darlington Point to Wagga 330 kV transmission line. A new voltage stability limit has been introduced in generation dispatch to cater for this contingency. With these emerging limitations, we have proposed augmentation expenditure in our Proposal to address the voltage stability shortfall.

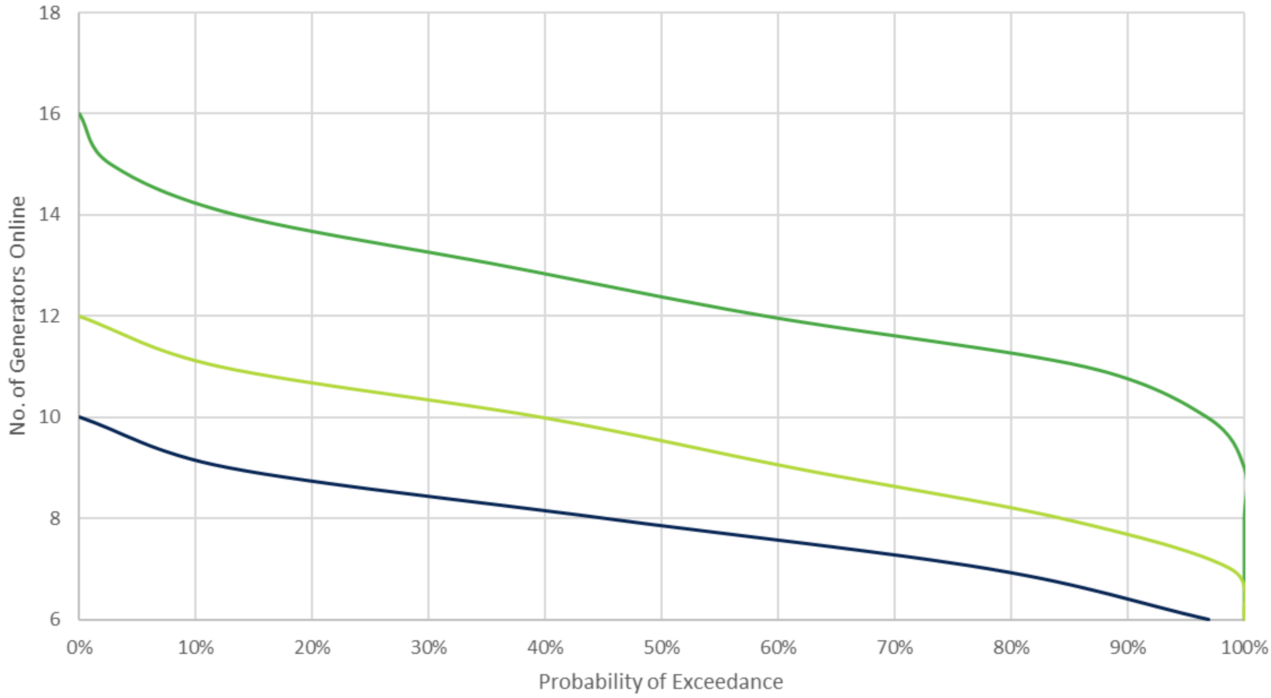
In the North West Slopes area of north-west NSW, emerging voltage control issues are forecast to materialise due to load growth from new and existing loads at Narrabri and Gunnedah. At times of low generation output and high loads, a trip of the Tamworth to Gunnedah 132 kV transmission line can cause voltage collapse between Narrabri and Gunnedah, and a trip of the Tamworth to Narrabri 132 kV line can cause under-voltages in that same area. With these limitations, we have proposed a continent project to address the voltage stability shortfall.

System strength

System strength will fall following the retirement of Liddell Power Station in 2023/24 and further reduce following each retirement of additional coal-fired generators.

Presently, coal-fired synchronous generators provide the majority of system strength in the NSW transmission network. With the reduction in the number of in-service synchronous rotating generators, a heavier reliance will be placed on synchronous condensers and other alternative technologies. System strength is analysed based on the system's ability to maintain the required minimum three-phase fault levels (specified by AEMO). A minimum of eight coal-fired synchronous generator units is required to meet the minimum fault levels needed at the fault level nodes as per AEMO's System Strength Requirements. As illustrated in Figure 8-5, system strength requirements are forecast to be breached within the next regulatory period.

Figure 8-5 Forecast System Strength Shortfalls in NSW

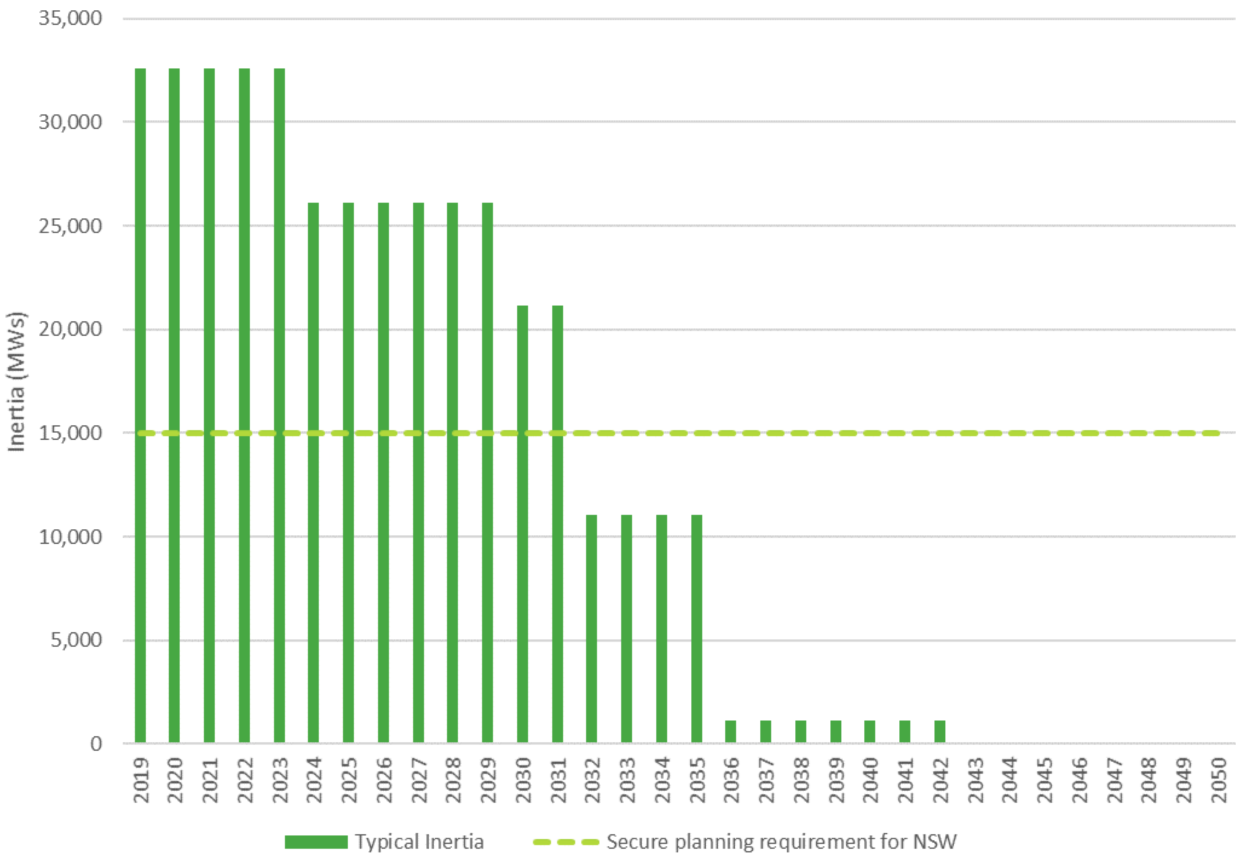


We have not included any system strength investments in our Augex forecasts in our Proposal, as the timing and extent of the investment required is currently uncertain. However, we have included investment to address a system strength gap as a contingent project, which would be triggered by the closure of non-renewable generation or a declaration of a system strength gap by AEMO.

Inertia

We also expect a shortfall in inertia following the retirements of Liddell, Vales Point and Eraring Power Stations or if coal-fired power stations move to flexible operation. However, we have included investment to address an inertia shortfall as a contingent project. Current forecast is just beyond the end of the next regulatory control period as illustrated in Figure 8-6, we have not included any inertia network services in our Augex forecasts in our Proposal, but have included as a contingent project, which would be triggered by closures of non-renewable generation.

Figure 8-6 Forecast inertia shortfalls in NSW



9. Supporting documentation

The following documents support our Augex submission for the 2023-28 regulatory period.

Asset Management System and Governance

- Asset Management System Description
- Network Asset Strategy
- Transmission Annual Planning Report (TAPR) 2021
- Energy Vision
- Prescribed Network Capital Investment Process
- Network Planning Framework

Business cases (OER justifications supporting forecast Augex)

- OER-1316 Maintain voltage in Beryl area
- OER-1440 Condition of Ausgrid cables 9SA and 92P
- OER-1443 Supply to Strathnairn area (Evoenergy)
- OER-1473 Manage multiple contingencies in North West NSW area
- OER-1491 Manage multiple contingencies in Sydney Northwest area
- OER-1522 Manage multiple contingencies in the Bayswater to Sydney area
- OER-1687 Supply to Western Sydney Priority Growth area
- OER-1698 Supply to Far West NSW Network
- OER-2137 Strategic property acquisition for Western Sydney Priority Growth Area
- OER-2145 Improve voltage control in Southern NSW area
- OER-2162 Increase capacity for generation in the Molong to Parkes area
- OER-N2205 Increase capacity for generation in Wagga North area
- OER-N2208 Increase capacity of 132 kV busbars at Wagga Substation
- OER-N2360 Maintain Voltage in the Vineyard Area
- OER-N2371 Supply to Sydney West Area
- OER-N2584 Maintain Voltage in Greater Sydney area
- OER-N2645 Maintain voltage in Alpine area
- OER-N2649 Voltage control under light load conditions
- AEMO – NCIPAP Endorsement Letter

Regulatory investment Tests for Transmission (RIT-T justifications supporting forecast major Augex)

- PSCR Bathurst, Orange and Parkes Supply[29]
- PSCR North West Slopes area supply[30]
- PADR Broken Hill Supply[31]
- PADR Improve stability of south-west NSW[32]
- PSCR Managing risk on Transmission Line 86[33]

Expert consultant documents (validation and verification of our Augex forecast and methodology)

- GHD - Demand driven Augex Forecast Review
- Aurecon - Point Load Study
- CutlerMerz - Transgrid 2023-28 Regulatory Proposal Augex Assurance Review

29 https://www.transgrid.com.au/projects-innovation/bathurst-orange-and-parkes-supply

30 https://www.transgrid.com.au/projects-innovation/north-slopes-area-supply

31 https://www.transgrid.com.au/projects-innovation/broken-hill-supply

32 https://www.transgrid.com.au/projects-innovation/improving-stability-in-south-west-nsw

33 https://www.transgrid.com.au/projects-innovation/managing-risk-on-line-86-tamworth-armidale

Attachment 1 – Nature of Augex

Our Augex forecast comprises projects and programs which can be categorised as follows:

- **Compliance**
- **Demand**
- **Economic Benefits**
- **System Services**.
- **Connections**
- **Strategic Property**.

These are discussed below.

We apply an established risk management framework to forecasting our Augex with a view to optimising cost, risk and performance for our customers while meeting our regulatory compliance obligations. We continue to evolve and improve our risk management frameworks to ensure we utilise new technology, data and process improvements. Our decisions on investment requirements are made through a robust process that connects our business objectives and stakeholder expectations to the outputs that we are committed to deliver. This alignment reflects how we combine our expertise in managing transmission assets, with our customers' and stakeholders' expectations, and our obligations to create a prudent and efficient plan for expenditure. Our investment decisions have now become increasingly data-driven, based on power system modelling, monitoring and data analytics, utilising probabilistic planning and robust demand forecasting to optimise investment timing and investment solutions.

Compliance

We have obligations under the NER and applicable jurisdictional instruments to ensure that our network performs within established boundaries of safety, reliability, and power quality. In general, limitations in the capacity and capability of the network manifest as a result of changes in demand and new connections to the network, with these limitations addressed through the Demand and Connections drivers of investment.

Our key compliance obligations under the NER pertain primarily to system strength, system security, thermal capacity, and the maintenance of voltage standards. With increasing levels of renewable generation connecting to our network and changes in the pattern of network flows, Augex projects are being driven by the need to ensure continued compliance with voltage, thermal and system strength requirements set out in the NER, as well as connection requirements. In several instances over the next regulatory period these obligations are expected to drive augmentation.

Further, from time-to-time compliance-driven investment needs emerge through "organic" or underlying incremental changes in network supply conditions. In these cases, projects may be raised to address emerging NER compliance issues, but these will often have associated economic benefits and may be justified on an economic benefits basis accordingly.

In addition to our obligations under the NER, network supply reliability standards are set by NSW Electricity Transmission Reliability and Performance Standard of 2017[34] (the NSW Reliability Standard) administered by IPART. We undertake a regular annual compliance review against this standard in accordance with our licence obligations, and identifies current or emerging non-compliances accordingly.

Further, we have obligations under our operating licence in the ACT[35] (administered by the ACT's Utilities Technical Regulator). These obligations, also reported on annually, ensure that we maintain adequate supply security and supply reliability at bulk supply points to the ACT in accordance with the terms of the relevant governing regulation.

We have a consistent compliance-based process that is applied across our network planning to assure and maintain compliance with our various supply obligations. This process comprises our understanding of current compliance obligations, material changes that require investment, and the evaluation and determination of solutions that are least cost in accordance with our business risk appetite statement.

In fulfilling these obligations, we manage and mitigate Expected Unserved Energy (EUE) risk commensurate with the prevailing Value of Customer Reliability (VCR) and in accordance with the requirements of our obligations under the various jurisdictional regimes.

The standards set by NSW and the ACT are economically derived and deterministic in nature. In particular, The NSW Reliability Standard specifies two reliability criteria for each Bulk Supply Point (BSP), the required level of network redundancy for each BSP (or group of BSPs that function as a cohort), and an allowance of Minutes of EUE, which is the maximum amount of energy-at-risk of being not supplied in a given year expressed as minutes at the average load on the BSP. In the ACT, there are specific requirements about the levels of redundancy provided at the various supply points, and respective supply security restoration requirements.

Both of these standards are planning standards rather than performance standards. This means the network needs to be planned to meet the standards over the lifecycle of the assets on average, rather than be met in every year. Whilst network augmentation investment may be required to ensure compliance with these standards, we seek flexibility in their application to promote the most efficient network or non-network solution to meet the Minutes of EUE allowance.

Notwithstanding these deterministic requirements, we calculate the benefits from reducing risk through meeting our compliance obligations (using the prevailing VCR), and compare these with the costs of the augmentation. Through power system modelling, performance monitoring and data analytics we are able to evaluate the power system requirements with respect of our compliance obligations. Drawing on this understanding, and by utilising non-network alternatives and new supply technologies (where possible), we aim to maximise the utilisation of our assets so that we can identify prudent deferral opportunities to optimise the timing of our Augex programs, thereby targeting expenditure in areas that provide the most value for our customers and other stakeholders.

In some cases, a negative net present value of benefits over costs may result with the options being assessed to address a compliance requirement. In such cases we select the option that provides the least

[34] https://www.ipart.nsw.gov.au/files/sharedassets/website/shared-files/licensing-compliance-electricity-transmission-reliability/nsw-electricity-transmission-reliability-and-performance-standard-2017.pdf

[35] http://www.legislation.act.gov.au/di/2016-189/current/pdf/2016-189.pdf

present value of cost. Alternatively, we can apply for a derogation from the respective regulatory authorities if there is a demonstrable benefit to customers by relaxing the standard at a particular location.

Demand

Both AEMO and our own maximum demand forecasts show only a slight increase in maximum demand in NSW as a whole in the next decade. Some bulk supply points including Central West, North West Slopes and Broken Hill are experiencing rapid load growth driven by new spot loads including data centres, mine expansion. Also rapid load growth in Western Sydney due to metro train lines and large commercial/residential development. The anticipated changes in demand have been discussed in Section 8.

Voltage issues have been identified in the central-west and north-west sub system network due to the mine and industry spot loads. In western Sydney region, the demand growth at Sydney West and Vineyard is forecast to exceed the BSP firm supply capability in next five to ten years. Augex projects to address those voltage and BSP supply capacity issues are required to allow us to meet our obligations under the NER and IPART standards.

Economic benefits

Low cost, zero emissions and geographically distributed renewable energy is displacing coal-fired generation at an unprecedented pace in the NEM. Increased levels of renewable energy generation in weaker parts of our network, is resulting in capacity and congestion issues for this generation to access the market. The more frequent constraining of generation dispatch has the potential to lead to higher energy prices, through the need to dispatch high-cost generation sources, or even to load shedding for customers.

The greatest benefits will come from the establishment of Renewable Energy Zones (REZ) integrating new, low-cost generation and improvements in interconnection. New electricity transmission infrastructure is essential to unlocking and accessing new generation sources and to enabling a secure, reliable and more affordable energy system. We are working closely with the NSW Government as part of the implementation of its Energy Infrastructure Roadmap to support the development of REZs in several areas of the state. We have also, separately, identified other areas which have high renewable development potential, and are seeking to coordinate investment in those areas in order to enable more low-cost generation sources to be accessed through our network.

We also have projects to support the reliability of the network through implementation of schemes to control events on the network which occur due to multiple contingencies and improvement in Remedial action schemes.

Our Proposal continues to work to improve the affordability of electricity by progressing transmission projects that will improve competition within the wholesale market, support the connection of more low-cost generation and reduce congestion on the network. Our Proposal identifies a number of possible contingent projects that could help to reduce prices for customers.

Given the position of our network at the heart of the NEM, the energy transition is also impacting the need for augmentation through the substantial interconnector and other major network upgrades identified by AEMO in the ISP. We are already implementing several ‘actionable ISP’ projects, and further actionable ISP projects will be treated as contingent projects for the forthcoming period.

Connections

Prescribed new connections relate to the connection of distribution loads connected to the DNSP network such as direct-connect customers and other spot loads. We provide connection solutions to our distribution customers at least cost.

Certainty around the magnitude, timing and location of new load, as well as an understanding of the diversity of the new load in how it will utilise the network capacity, is essential in how we identify prudent augmentation solutions for new distribution connections.

Attachment 2 – Explanation of forecast expenditure

Introduction

This chapter provides a high-level explanation of the forecast expenditure for each Augex category.

The table below lists each Augex category and the forecast capex over the forthcoming regulatory period.

Table A2 - 1 Total escalated capex forecasts by RIN category ($Million, Real 2022-23)

	Cross reference to supporting documents	Expenditure forecast ($M, real 2022-23)	Percentage of Augex
Base Augmentation	2021 Transgrid Transmission Annual Planning Report (TAPR) Option Evaluation Reports	161.6	63.7%
Compliance		*36.9*	*14.5%*
Demand		*85.2*	*33.6%*
Economic Benefits		*39.6*	*15.6%*
System Services		-	-
Connections		2.9	1.1%
Strategic Property		[redacted]	[redacted]
Supply to Western Sydney Priority Growth area		[redacted]	[redacted]
Total (Excl. NCIPAP)		**253.6**	**100.0%**
NCIPAP	2023-28 NCIPAP Projects AEMO NCIPAP Endorsement Letter	16.2	N/A
Total (Incl. NCIPAP)		**269.8**	**N/A**

The table below lists each driver and the forecast capex over the forthcoming regulatory period.

Table A2 - 2 Total escalated capex forecasts by driver ($Million, Real 2022-23)

	Cross reference to supporting documents	Expenditure forecast ($M, real 2022-23)	Percentage of Augex
Compliance	2021 Transgrid Transmission Annual Planning Report (TAPR)	[redacted]	[redacted]
Demand		[redacted]	[redacted]
Economic Benefits		[redacted]	[redacted]
Strategic Property		[redacted]	[redacted]
Augex - Major Project		[redacted]	[redacted]
Connections		[redacted]	[redacted]
Total Escalated Augex		**253.6**	**100.0%**

[redacted]

The following table sets out our key Augex projects for our 2023-28 Revenue Proposal, and their relation to the external drivers and Augex categories identified.

Table A2 - 3 Key Augex projects – Forecast capex ($Million, Real 2022-23)

Augex Projects	2023-28 M, $Real 2022-23	Timeframe for project completion	External Drivers / Augex Categories
Proposed projects in the 2023-28 capex forecast			
Increase capacity of 132 kV busbars at Wagga Substation	5.2	2026/27	**Economic conditions** > Network congestion, where projects have benefits exceeding costs
Supply to Sydney West Area	17.4	2024/25	**Economic conditions** > Demand - Spot load growth > Demand - Organic load growth
Voltage control under light load conditions	4.8	2024/25	**Changing generation mix** > Compliance - NER voltage compliance > Demand - reduction in minimum demand
Maintain Voltage in Beryl Area	20.9	2026/27	**Economic conditions** > Compliance - NER voltage compliance > Demand - Organic load growth
Supply to Western Sydney Priority Growth area	[redacted]	2027/28	**Economic conditions** > Demand - Spot load growth > Demand - Underlying organic load growth > Compliance - IPART reliability standards related to expected unserved energy
Supply to Far West NSW Network	8.4	2028/29	**Economic conditions** > Demand - Spot load growth > Compliance - IPART reliability standards related to expected unserved energy
Maintain Voltage in the Vineyard area	38.4	2025/26	**Economic conditions** > Compliance – NER voltage stability compliance > Demand - Organic load growth
Maintain Voltage in Alpine area	2.1	2029/30	**Economic conditions** > Compliance – NER voltage stability compliance > Demand - Organic load growth > Demand - Spot load growth
Improve voltage control in Southern NSW area	21.0	2026/27	**Changing generation mix** > Compliance - NER voltage compliance > Increasing renewable generation > Demand - Changes in minimum demand

Augex Projects	2023-28 M, $Real 2022-23	Timeframe for project completion	External Drivers / Augex Categories
Increase capacity for generation in the Molong to Parkes area	6.6	2024/25	**Changing generation mix** > Economic Benefits - Network congestion, where projects have benefits exceeding costs
Increase capacity for generation in Wagga North area	10.3	2024/25	**Changing generation mix** > Economic Benefits - Network congestion, where projects have benefits exceeding costs
Maintain Voltage in Greater Sydney area	9.0	2025/26	**Economic conditions** > Compliance – NER voltage compliance
Manage multiple contingencies in Sydney Northwest area	10.1	2028/29	**Economic conditions & Climate Change** > Economic Benefits – Cost benefits to manage the High Impact Low Probability event > Compliance - NER requirements for non-credible contingencies
Manage multiple contingencies in North West NSW area	2.7	2025/26	**Economic conditions & Climate Change** > Economic Benefits – Cost benefits to manage the High Impact Low Probability event > Compliance - NER requirements for non-credible contingencies
Manage multiple contingencies in the Bayswater to Sydney area	4.7	2026/27	**Economic conditions & Climate Change** > Economic Benefits – Cost benefits to manage the High Impact Low Probability event > Compliance - NER requirements for non-credible contingencies
Supply to Strathnairn area (Evoenergy)	2.7	2027/28	**Economic conditions** > Joint Planning – Load growth
Strategic property acquisition near Kemps Creek	[redacted]	2023/24	**Economic conditions** > Strategic property
Total	**274.2**		
Standard contingent projects not included in the 2023-28 capex forecast			
Meeting NSW system strength requirement during the system strength transition period	283.7	2025/26	**Changing generation mix** > System services - AEMO system announced strength gap
Meeting NSW system inertia requirement	105.1	2030/31	**Changing generation mix** > System services - AEMO system announced inertia gap

Augex Projects	2023-28 M, $Real 2022-23	Timeframe for project completion	External Drivers / Augex Categories
Improving stability in South-Western NSW > Undergoing RIT-T process > PSCR: Jul 2020 > PADR: Sep 2021 > PACR: Mar 2022	127.1	2024/25	**Changing generation mix** > Network congestion, where projects have benefits exceeding costs
Improve capacity of southern NSW lines for renewables	275.8	2029/30	**Changing generation mix** > Network congestion, where projects have benefits exceeding costs
Moree Special Activation Precinct	42.0	2027/28	**Economic conditions** > Demand - Spot load growth
Supply to North West Slopes Undergoing RIT-T process > PSCR: Apr 2021 > PADR: Feb 2022 > PACR: Jun 2022	166.3	2027/28	**Economic conditions** > Compliance - NER voltage compliance > Demand - Mining spot load growth > Demand - Underlying organic load growth > Compliance - IPART reliability standards related to expected unserved energy
Supply to Bathurst Orange Parkes Stage 1 Undergoing RIT-T > PSCR: Mar 2021 > PADR: Feb 2022 > PACR: Jun 2022	117.4	• 2026/27	**Economic conditions** • Demand - Mining spot load growth • Demand - Underlying organic load growth • Compliance - NER voltage compliance • Compliance - IPART reliability standards related to expected unserved energy
Bathurst Orange Parkes Stage 2	94.6	2030/31	**Economic conditions** > Demand - Mining spot load growth > Compliance - NER voltage compliance > Compliance - IPART reliability standards related to expected unserved energy
Managing risk on Line 86 Undergoing RIT-T • PSCR: Dec 2021 • PADR: May 2022 • PACR: Jul 2022	331.1	2027/28	**Changing generation mix** > Network congestion, where projects have benefits exceeding costs

Augex Projects	2023-28 M, $Real 2022-23	Timeframe for project completion	External Drivers / Augex Categories
Supply to ACT network capability	71.4	2028/29	**Economic conditions** > Compliance – UTR licence conditions > Demand - Underlying organic load growth
Manage increased fault levels in Southern NSW	51.1	2026/27	**Changing generation mix** > Fault level compliance
Strategic Easement acquisition for supply to Sydney from the south	252.2	2025/26	**Economic conditions** > Strategic property
Total	**1,917.7**		

The following sections set out our largest Augex projects included in our 2023-28 Revenue Proposal forecast.

Supply to Western Sydney Priority Growth area

Table A2 - 4 Supply to Western Sydney Priority Growth area summary

Supply to Western Sydney Priority Growth area	
Description	Development of the Western Sydney International Airport leads to the significant demand growth in Western Sydney Aerotropolis precinct. Endeavour Energy has proposed new 132 kV sub-transmission network for supplying the new Western Sydney Parklands City load. The new development will create a 132 kV flow path in parallel with the 330 kV network between Macarthur and Sydney West BSPs. Overloading will occur at Macarthur BSP and on Endeavour Energy's sub-transmission lines between Macarthur and Nepean during periods of medium to high demand under system normal conditions for the proposed network development.
Deliverables	The 2023-2028 regulatory period will include: > Establish a new 330/132 kV bulk supply point at Kemps Creek next to existing 500/330 kV substation, with two 375 MVA transformers > Construct an additional 330/132 kV transformer at Macarthur Substation > Facilitate the connection works at Macarthur Substation for Endeavour Energy to convert 66 kV line 85L to 132 kV line 9L2.
Objectives	Maintain the reliability and supply capability to Endeavour Energy's Western Sydney distribution network
Main drivers of expenditure	Load growth
Expenditure forecasting methodology	Our Network Planning team undergo an analysis of load growth and spot load developments provided by DNSPs to determine the expected unserved energy and forecast compliance gaps, options to address these, and a cost-benefit analysis to determine the preferred option. The forecast methodology is in accordance with our Prescribed Capital Investment Process. Following identification of needs and option scoping, an evaluation is undertaken to determine the best course of action for the need. This takes into account the NPV for the various options using expected unserved energy and considers varying scenarios to test sensitivities in the NPV analysis.
Historic and forecast expenditure	The proposed expenditure in the 2023-2028 period is $[redacted] million
Principal reasons for proposed expenditure	Maintain network reliability and compliance with IPART reliability standards
Validation	The underlying load assumptions have been validated through: > Comparison of Transgrid and AEMO forecasts > Challenge to distributor forecasts > Independent reviews of future NSW loads
Benefits	The project will result in the following benefits:

	> Maintain network reliability > Reduced Expected Unserved Energy
Procurement	Power transformers are typically procured from a small number of pre-qualified manufacturers. This allows competitive pricing while standardising on a relatively small number of suppliers to reduce diversity, spares holdings and design effort. Design and installation is managed by our construction teams using external resources engaged through a competitive tendering process.
Supporting documents and Model	This expenditure is supported by the following documents: > OER 1687

Maintain voltage in the Vineyard area

Table A2 - 5 Maintain voltage in the Vineyard area summary

Maintain voltage in the Vineyard area	
Description	Total demand on Vineyard BSP is presently limited to 666 MVA to meet reactive margin requirements under the NER. As a result of increasing forecast demand growth in the Vineyard area, the reactive margin at Vineyard 330 kV and 132 kV busbars will drop to below one percent of the fault level (NER S5.1.8) at those locations from summer 2024/25 under a single credible contingency of the 330 kV Line 29 that supplies the Vineyard BSP from Sydney West. To maintain the required reactive margin if the contingency occurs during high demand, load curtailment would be required from Summer 2024/25 based on the POE50 demand forecast.
Deliverables	The 2023-2028 regulatory period will include: > Loop-in line 26 to Vineyard 330 kV Substation > Installation of an additional 330 kV busbar diameter to allow connection of line 26.
Objectives	Maintaining reactive margin (voltage stability) limits at Vineyard Bulk Supply Point (BSP)
Main drivers of expenditure	Load growth
Expenditure forecasting methodology	Our Network Planning team undergo an analysis of load growth and spot load developments provided by DNSPs to determine the expected unserved energy and forecast compliance gaps, options to address these, and a cost-benefit analysis to determine the preferred option. The forecast methodology is in accordance with our Prescribed Capital Investment Process. Following identification of needs and option scoping, an evaluation is undertaken to determine the best course of action for the need. This takes into account the NPV for the various options using expected unserved energy and considers varying scenarios to test sensitivities in the NPV analysis.
Historic and forecast expenditure	The proposed expenditure in the 2023-2028 period is $38.4 million

Principal reasons for proposed expenditure	Compliance with NER voltage stability requirements
Validation	The underlying load assumptions have been validated through: > Comparison of Transgrid and AEMO forecasts > Challenge to distributor forecasts > Independent reviews of future NSW loads
Benefits	The project will result in the following benefits: > Maintain network reliability > Reduced Expected Unserved Energy
Procurement	Substation plant and equipment are typically procured from a small number of pre-qualified manufacturers or from existing competitively sourced period orders. This allows competitive pricing while standardising on a relatively small number of suppliers to reduce diversity, spares holdings and design effort. Design and installation is managed by our construction teams using external resources engaged through a competitive tendering process.
Supporting documents and Model	This expenditure is supported by the following documents: > OER N2534

Strategic Property

Table A2 - 6 Strategic Property summary

Strategic Property	
Description	Strategic property acquisitions are proposed for the following needs: > Strategic property acquisition for Western Sydney Priority Growth Area A new Western Sydney bulk supply point will be required to supply the growing Western Sydney demand. Land south of the existing Kemps Creek 500/330 kV Substation is identified as a suitable site with its access to the 330 kV and 500 kV network, and close-proximity to the load centre. There is a window of opportunity to secure the land south of Kemps Creek Substation while it is still available, prior to the surrounding land in the area being built out, which is currently occurring rapidly. Alternate locations for the BSP are likely to be higher-cost solutions because they will be a further distance from the existing Kemps Creek 500/330 kV Substation, requiring additional underground 330 kV cable connections back to Kemps Creek or another close-by substation.
Deliverables	The 2023-2028 regulatory period will include: > Purchase of strategic land in Western Sydney and near Wagga Wagga

Objectives	Strategic purchase of land and easements to support future infrastructure where the land may not be economically available in the future
Main drivers of expenditure	Facilitate future projects
Expenditure forecasting methodology	Our Network Planning team undergo an analysis of load growth and spot load developments provided by DNSPs to determine any required works to support these developments. The long-term outlook is also identified, seeing what projects may be required in which it will be difficult to secure properties for in the future, including ISP projects. The forecast methodology is in accordance with our Prescribed Capital Investment Process. Following identification of needs that may require strategic property purchases, land options are considered, and the most preferable locations that would likely reduce long-term costs are identified. These are then scoped by internal staff and external experts. An evaluation is then undertaken.
Historic and forecast expenditure	The proposed expenditure in the 2023-2028 period is $[redacted] million
Principal reasons for proposed expenditure	Strategic land acquisition
Validation	The costing for the acquisitions were informed by external exports JLL
Benefits	The project will result in the following benefits: > Acquire land prior to areas becoming overly developed, or the purchase price increases substantially
Procurement	The following strategic procurements will be required: > Land south of Kemps Creek Substation > Strategic corridor in South Western NSW
Supporting documents and Model	This expenditure is supported by the following documents: > OER 2137

Connections

Table A2 - 7 Connections summary

Connections	
Description	Maximum demand in the West Belconnen area in the ACT is expected to increase due to the load growth in the new and developing suburbs of Strathnairn and Macnamara. There is a Need to meet the expected demand growth in this area. The option to construct a new 132/11 kV zone substation (ZS) in Strathnairn is being considered by Evoenergy to supply the forecasted load growth.
Deliverables	The 2023-2028 regulatory period will include: > Facilitate the connection of the Strathnairn ZS.

Objectives	To meet the network reliability requirements
Main drivers of expenditure	Load growth
Expenditure forecasting methodology	Our Network Planning team undergo an analysis of load growth and spot load developments provided by DNSPs to determine any required works to support these developments. The forecast methodology is in accordance with our Prescribed Capital Investment Process. Following identification of needs and option scoping, an evaluation is undertaken to determine the best course of action for the need. This takes into account the NPV for the various options using unserved energy and an externally built NPV tool.
Historic and forecast expenditure	The proposed expenditure in the 2023-2028 period is $2.9 million
Principal reasons for proposed expenditure	To meet the network reliability requirements
Validation	The underlying load assumptions have been validated through: > Comparison of Transgrid and AEMO forecasts > Challenge to distributor forecasts > Independent reviews of future NSW loads
Benefits	The project will result in the following benefits: > Supply to new suburbs supplied by Evoenergy.
Procurement	The following procurement will be required for the project: > Installation of a new 132 kV switchbay at Canberra substation and associated ancillary works.
Supporting documents and Model	This expenditure is supported by the following documents: > OER 1443