Preliminary Revenue Proposal
2023–2028

Transgrid

Table of contents

A message from our CEO

I am pleased to present this Preliminary Revenue Proposal for the 2023-28 regulatory period and invite feedback from our customers and other stakeholders, ahead of submitting our Revenue Proposal to the Australian Energy Regulator in January 2022.

Australia's electricity system is undergoing profound change. The New South Wales (NSW)[1] and Australian Capital Territory (ACT)[2] Governments have adopted a 2050, or sooner, goal of net zero emissions to deliver environmental sustainability.[3]

We are committed to working with the Governments to achieve their goals. As Australia's largest electricity transmission network[4], we are at the heart of the energy transformation and our infrastructure is vital to achieving the net zero emissions target. We are already leading the energy transition by investing in Powering Sydney's Future, the Queensland to NSW Interconnector Minor Upgrade, the Victoria to NSW Interconnector Minor Upgrade and Project EnergyConnect. We will also invest in HumeLink once the Australian Energy Regulator provides regulatory approval. These investments will significantly reduce customers' total electricity bills by delivering wholesale market savings.

Over the current period we have continued to invest in the safety, security and reliability of our transmission network:

- we delivered Powering Sydney's Future (PSF), which was necessary for the continued safe and reliable power supply to the people working and living in Sydney's CBD
- we built a new 330/132kV substation at Stockdill to ensure continued compliance with our reliability requirements
- we are investing to meet our network regulatory obligations and other compliance requirements, in light of load increases driven by economic growth, as well as the impact of changes in the generation mix, and
- we also acted quickly to keep the community and our people safe and to minimise disruptions to our transmission services during increasingly frequent extreme weather events, including the 2019-20 bushfires, which were the worst in NSW history.

In the next five years we will invest to maintain our current service while responding to our key operational challenges. Our proposal includes investment to:

- replace and upgrade assets to maintain network performance to address our aging asset base. We will replace assets with more resilient alternatives to withstand more frequent climate-driven natural hazard events
- continue to maintain the stability of our network as the generation mix changes due to decarbonisation. Our proposal includes investments to improve fault levels in Southern NSW to ensure compliance with our regulatory obligations
- meet strong maximum demand growth in regions such as western Sydney (Sydney Priority Growth area), North West Slopes and Bathurst, Orange and Parkes, and
- enhance our network cyber and physical security in line with new obligations under the Australian Government's proposed new critical infrastructure framework[5].

We will also deliver projects identified in the Australian Energy Market Operator's (AEMO) Integrated System Plans (ISP) as they are required, including through the automatic contingent project provisions for actionable ISP projects. The costs of these projects are not included in our expenditure forecasts in this proposal so that customers will only pay for these projects if AEMO determines they are needed.

This Preliminary Revenue Proposal shows how in the next five years we will address our operational challenges and deliver the outcomes we understand our customers value most – safety, security, reliability, sustainability and affordability. All the efficiencies and innovations we have delivered in the 2018-23 period are fully built into our proposal. This provides a strong foundation from which we can further innovate and deliver efficient transmission services and benefits to our customers over the 2023-28 period.

We look forward to working with our customers, stakeholders, governments and industry, as we deliver the power system of the future, serving the needs of today and generations to come, and invite your input on this document.

Brian Salter
Acting Chief Executive Officer
October 2021

1 NSW Government - Department of Planning, Industry and Environment (DPIE) Net Zero Plan Stage 1: 2020-2030.
2 The targets, set under the Climate Change and Greenhouse Gas Reduction Act 2010.
3 Meet the 1.5°C global warming target in the Paris Agreement.
4 We have the highest customer base, peak demand, system demand and energy served of the network businesses in the national electricity market.
5 The Australian Government's Critical Infrastructure 2020 Bill, which is expected to be passed early in 2022.

1. Snapshot of our Preliminary Revenue Proposal

Our Preliminary Revenue Proposal delivers customer savings and a safe, reliable, and secure network in a rapidly changing power system.

Customer savings

$16.90 p.a. residential

$61.20 p.a. small business

Delivering customer savings

Affordability is customers' highest priority.

Transmission savings[6]:

- **$16.90 p.a.** residential savings
- **$61.20 p.a.** small business savings

Wholesale energy savings:

- Project EnergyConnect delivers annual residential savings of up to **$64 p.a.**[7]

Ensuring safety, security and reliability

This is fundamental to our service offering in an increasingly complex operating environment.

- **Replace and upgrade** assets to maintain network performance
- **Maintain** power quality to support the changing generation mix
- **Improve** network resilience to climate-driven natural hazard events
- **Enhance** cyber and physical security

6 Expected reduction in the average annual residential and small business bills over the regulatory period (indicative price at 2022-23 compared to 2027-28).

7 Assuming: (i) wholesale price changes; (ii) the cost of EnergyConnect; and (iii) the effect of the Project on existing interconnector residues, are fully passed on to consumer retail bills, and average annual household consumption figures remain constant over time.

All dollar values in this document are presented in end-year (to 30 June) real 2022-23 dollars unless otherwise specified.

Leading the energy transition

We must lead the transition given our central role in the energy market.

- **Construct** Project EnergyConnect
- **Upgrade** Queensland to NSW Interconnector
- **Upgrade** Victoria to NSW Interconnector
- **Construct** HumeLink, once approved[8]

Meeting rapid load growth

We need to meet rapid growth in demand where it is occurring.

- **Western Sydney** Priority Growth area
- **North West Slopes Area** project, covering Tamworth, Narrabri and Gunnedah Peak
- Supply to **Bathurst, Orange and Parkes**

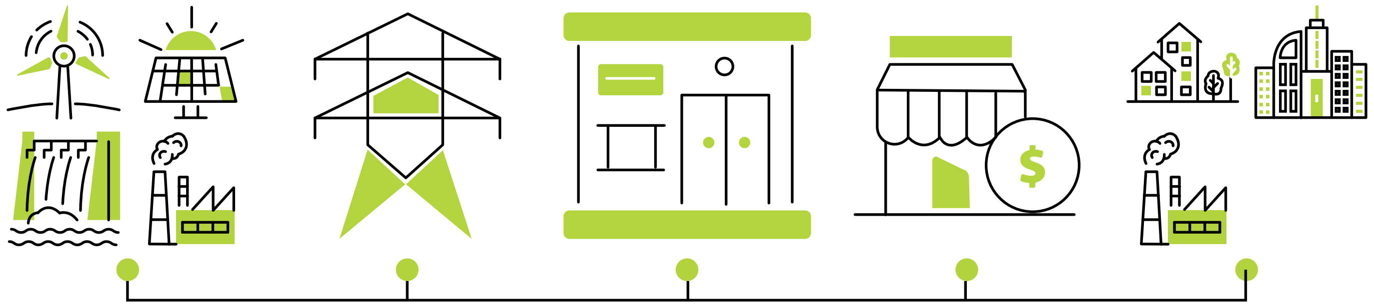
8 We will invest in HumeLink once the AER provides regulatory approval.

2. About us and our network

Our role in the electricity supply chain

Our transmission network is at the heart of the National Electricity Market (NEM) and is vital to achieving NSW and ACT's net zero emissions target.

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



Generation and storage

Electricity is generated from a range of energy sources including wind, solar, hydro, coal and gas.

Grid-scale batteries are also emerging and have the potential to help maintain reliable supply during times of peak demand.

Transmission

The transmission network connects to large generators and transports electricity long distances to large directly-connected industrial customers and distribution networks that deliver it to homes and businesses.

Distribution

Distribution networks transport electricity at lower voltages to households and businesses. They also provide metering services to measure the amount of electricity being consumed.

Retail

Retailers are responsible for billing customers for the electricity they use and managing payments. There are approximately 102 electricity retailers operating in NSW and the ACT.

Customers

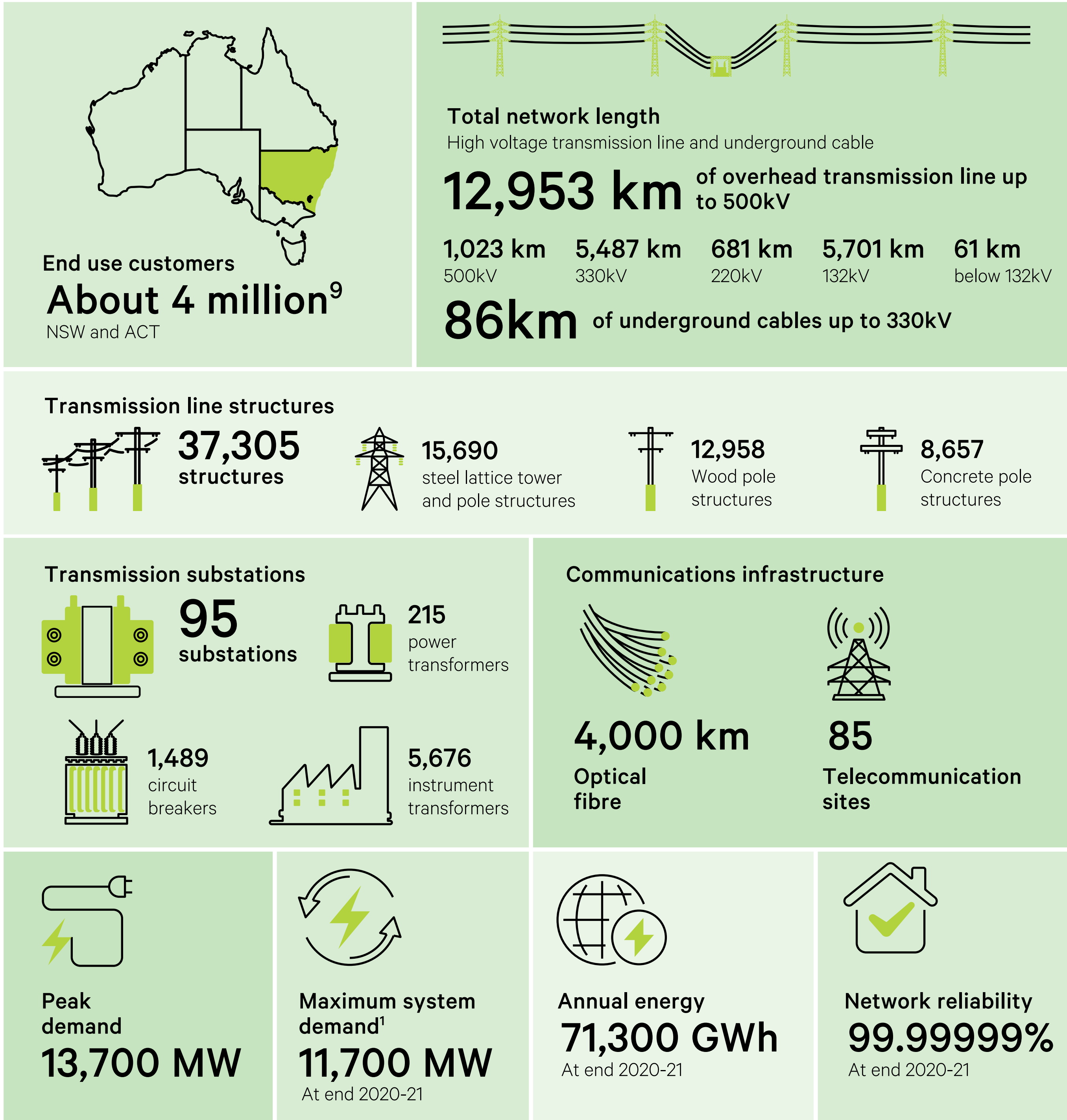
There are around four million electricity customers in NSW and the ACT. Increasingly our customers generate their own electricity through rooftop solar and feed surplus electricity back to the grid, impacting the traditional flow of electricity.

Our network assets and performance

We have the highest peak and system demand in the NEM and transport almost 40 per cent of the energy in the NEM, more than any other network business.

Our transmission network is the backbone of the NEM and underpins the Australian economy by facilitating energy trading between Australia's most populous states. It comprises 95 substations, over 13,039 kilometres of high voltage transmission lines, underground cables and five interconnections between NSW and ACT and Queensland and Victoria.

Figure 2.2: Our assets and network performance



Notes: 1. Transmission system coincident maximum demand in 2020-21, which occurred on 10 June 2021.
9 Economic Insights, AER TNSP Benchmarking Report Draft, August 2021.

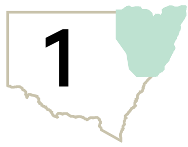
Our geographic coverage

We operate and manage Australia's largest electricity transmission network.

We operate the high voltage transmission network in NSW and the ACT, which services about 4 million[10] customers. Our transmission network:

- supports secure and reliable electricity supply to Sydney, the nation's largest city, and Canberra, the nation's capital
- facilitates grid connection for new generators, including a rapidly growing number of renewable energy resources, and
- is central to the NEM, enabling generator competition and energy trading in the NEM to the benefit of all electricity consumers.

As shown in Figure 2.1 our transmission network comprises:

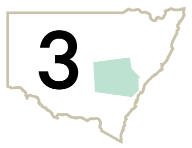


Northern NSW

This region covers from Tomago to Lismore in the north-eastern corner of NSW, north-west through to Moree and back to Tamworth. Our network connects with Queensland in the north.

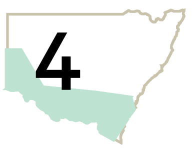
Greater Sydney

This region includes the CBD of Sydney, which is a hub for economic activity, major transport infrastructure, industry and tourism, as well as the Blue Mountains, Wollongong, the Central Coast and Newcastle. A high level of reliability and security is required to maintain services required for Sydney to operate as a major international city.



Central West NSW

This region connects to Greater Sydney at Mt Piper and Wallerawang and extends west to Orange, Parkes and Forbes. It extends up to Wellington and Wollar where it connects to Northern NSW and down to Cowra where it connects to Southern NSW at Yass.

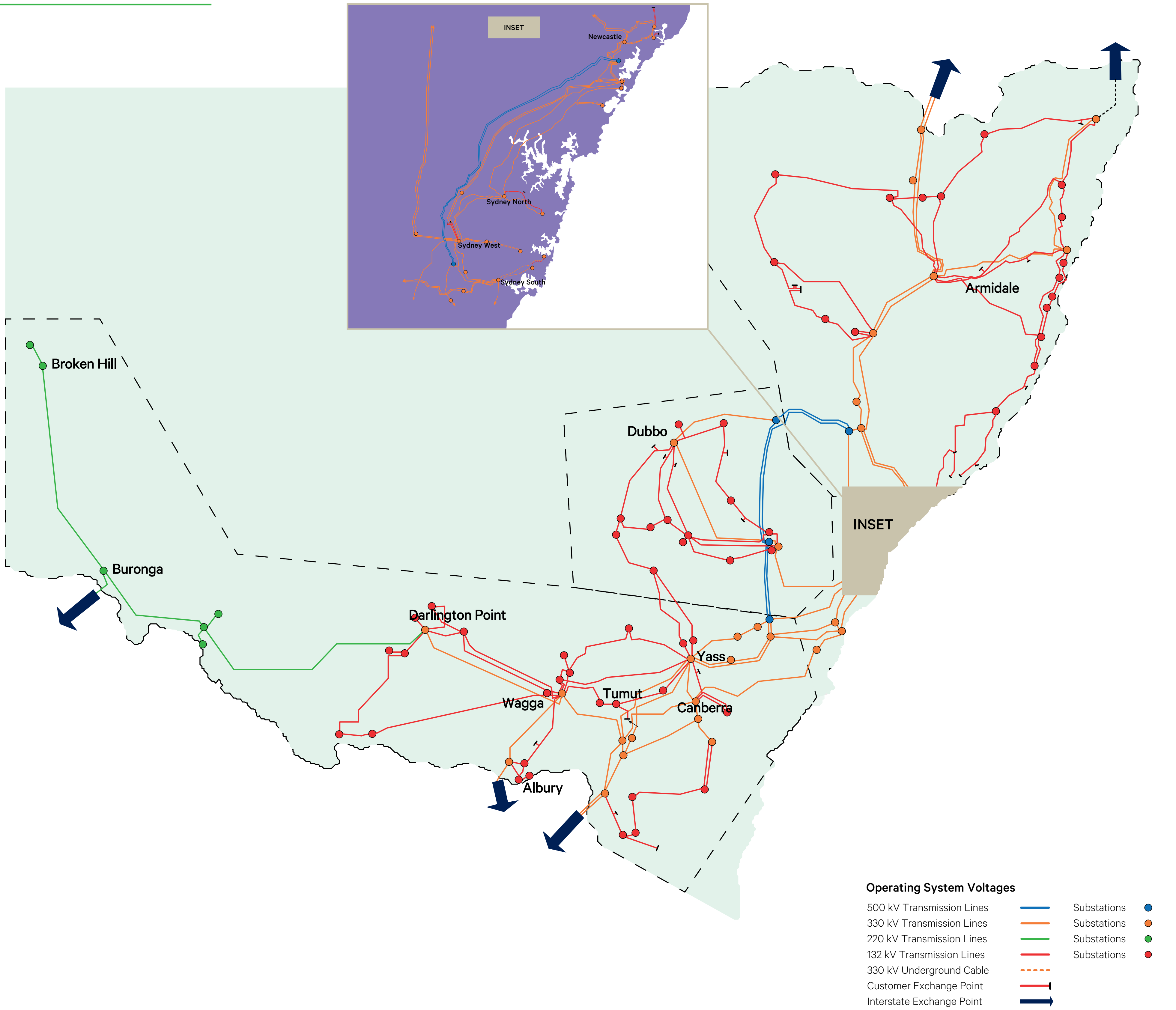


Southern NSW and ACT

This region covers Marulan to Wagga Wagga in the south of the State, to Albury in the far-south, and extends to Broken Hill in the far-west. This region includes the ACT, and connects with Victoria in the south, and will soon connect with South Australia once Project EnergyConnect is operational.

10 Economic Insights, AER TNSP Benchmarking Report Draft, August 2021.

Figure 2.1: NSW transmission network



Leading the energy transition

We will lead the energy transition to achieve the NSW and ACT Governments' goals of net zero emissions.

Australia's energy system is undergoing a once-in-a-generation transformation. The transition to a new energy market is happening quickly, as the cost of renewables decline, technology advances, and governments commit to decarbonisation.

The NSW[11] and ACT[12] Governments have both adopted a goal of achieving zero emissions by 2050, or sooner. By 2030, the NSW Government's goal is to reduce emissions by 50 per cent against 2005 levels. By 2025, the ACT Government's goal is to reduce emissions by at least 50 per cent against 1990 levels.

We are committed to working with the NSW and ACT Governments to achieve their goals. In particular, we are working closely with the NSW Government on its Energy Roadmap, which is expected to see the development of five Renewable Energy Zones.

As Australia's largest electricity transmission network, our infrastructure is vital to Australia's successful energy transition and achieving net zero emissions. Decarbonisation, electrification and new green industries require a significant expansion of renewable generation and associated transmission infrastructure.

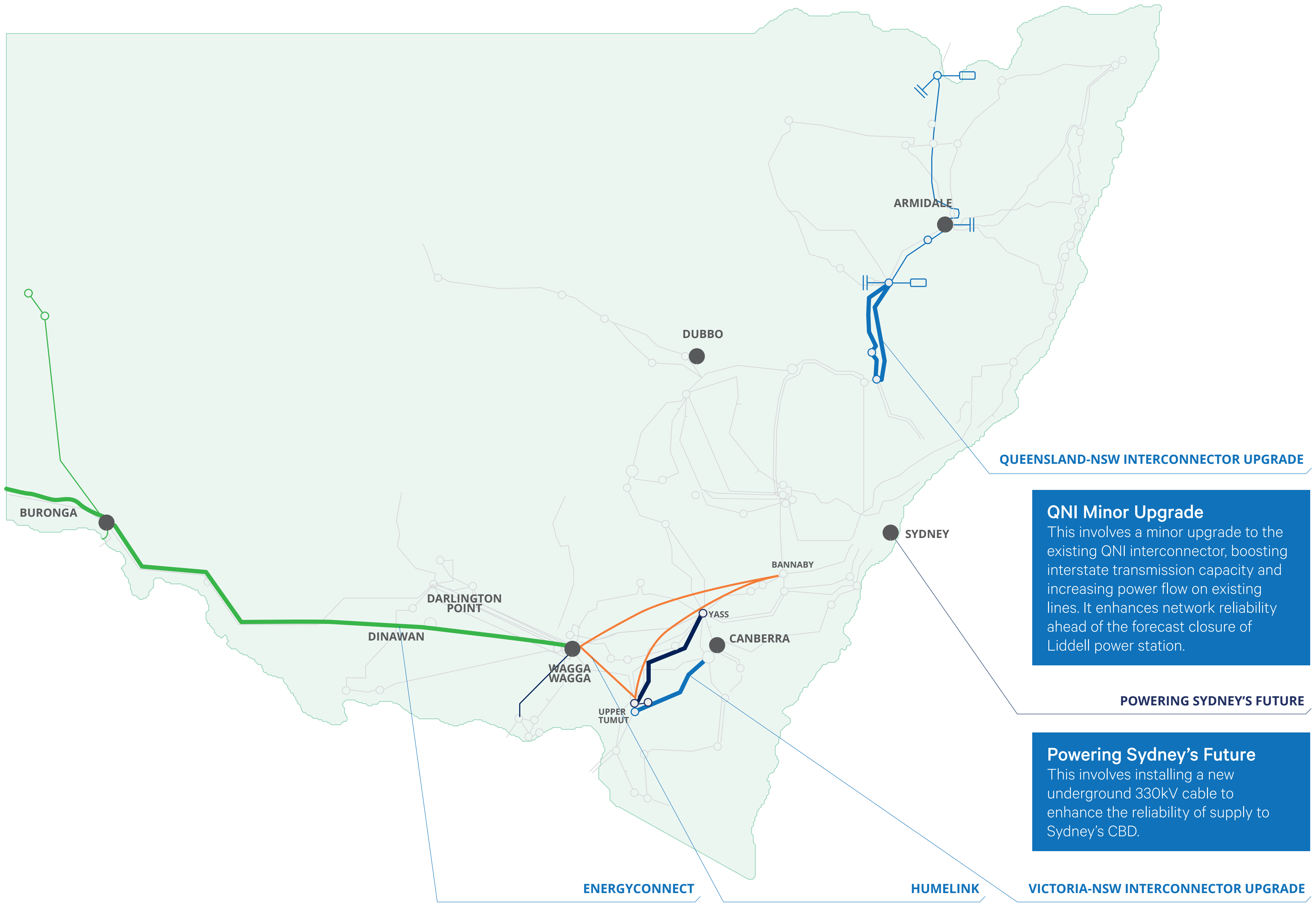
AEMO's Integrated System Plan (ISP) identifies the optional development path for eastern Australia's power system to facilitate this transition. The ISP identifies the necessary transmission network investments to optimise consumer benefits.

We are leading the energy transition in the current period by investing in Powering Sydney's Future (PSF) and three nationally significant ISP projects identified in the optimal development path in AEMO's ISP. These projects are critical to enabling the energy market transition and will significantly reduce customers' overall electricity bills by delivering wholesale market cost reductions. We will also invest in HumeLink once the AER provides regulatory approval[13].

In the 2023-28 period, we will deliver projects identified in AEMO's ISPs as they are required, in accordance with the automatic contingent project provisions for actionable ISP projects. The costs of these projects are therefore not included in our expenditure forecasts in this proposal and customers will only pay for these projects if AEMO determines that they are needed.

Our capital expenditure for the next regulatory period focuses on:

- Changes in the generation mix due to decarbonisation
- Strong maximum demand growth due to economic growth in some regions, including western Sydney
- Our aging asset base
- Cyber and physical infrastructure threats, and
- More frequent and severe extreme weather events.



QNI Minor Upgrade
This involves a minor upgrade to the existing QNI interconnector, boosting interstate transmission capacity and increasing power flow on existing lines. It enhances network reliability ahead of the forecast closure of Liddell power station.

Powering Sydney's Future
This involves installing a new underground 330kV cable to enhance the reliability of supply to Sydney's CBD.

Project EnergyConnect
This involves constructing new 330 kV double circuit transmission lines, with approximately 800 MW transfer capacity that will connect SA and NSW, with an added connection to north-west Victoria.

HumeLink
This involves new 500kV lines in an electrical 'loop' between Maragle, Wagga Wagga and Bannaby. It will open up additional capacity for new generation (primarily renewable generation) in southern NSW, increase the transfer capacity between Victoria and NSW and reduce customers' final electricity bills by improving wholesale market competition.

VNI Minor Upgrade
This is the NSW component of works to upgrade the existing VNI interconnector. It is essential to manage the risk of reliability standard breaches during extreme heat conditions in Victoria, following the closure of Liddell power station[14]. The project is also expected to support the development of renewable generation and incorporates the use of Smart Wires' technology that enables dynamic control of power flows.

11 NSW Government - Department of Planning, Industry and Environment (DPIE) Net Zero Plan Stage 1: 2020-2030.
12 The targets, set under the Climate Change and Greenhouse Gas Reduction Act 2010.
13 We published the Project Assessment Conclusions Report (PACR) on 29 July 2021. We will shortly submit our feedback loop request to AEMO in accordance with the new ISP Rules and subject to AEMO confirming that HumeLink remains on the optimal development path, we will submit our initial Contingent Project Application to the AER.

14 AEMO, 2019 Electricity Statement of Opportunities (ESOO), p. 5.

3. Customer input into our Revenue Proposal

We invite feedback on this Preliminary Revenue Proposal to inform our Revenue Proposal, which we will submit to the AER on 31 January 2022.

We rely on engagement to inform our decisions, and to ensure our services meet our customers' and other stakeholders' needs in a rapidly changing energy system.

This document reflects the feedback we have received to date and invites feedback on our proposals to inform our Revenue Proposal which we will submit to the AER by 31 January 2022.

Our Stakeholder Engagement Plan details our consultation program for our
2023-28 Revenue Proposal
Further information on our engagement program is available on our website.

Our engagement program includes the TransGrid Advisory Council (TAC) as well as customer research and our annual stakeholder perception survey.

TransGrid Advisory Council

The TAC is the primary channel for engaging on our Revenue Proposal. We have expanded its membership to include a broader range of stakeholder organisations. Members of the TAC represent customer groups, business, finance, academia as well as the energy industry. Further information on our TAC is available here.

We are holding interactive 'deep-dive' workshops with our TAC and AER representatives to discuss our proposals.

Customer research

We have partnered with the independent consumer research expert Forethought to research our customers' priorities and preferences. This research comprises three phases:

Phase 1
Explore customer needs, expectations and attitudes to identify key areas to focus the research.

Phase 2
Prioritise customers' concerns and identify issues most relevant to transmission networks.

Phase 3
Test parts of our reset proposal with customers directly and get feedback on areas for refinement.

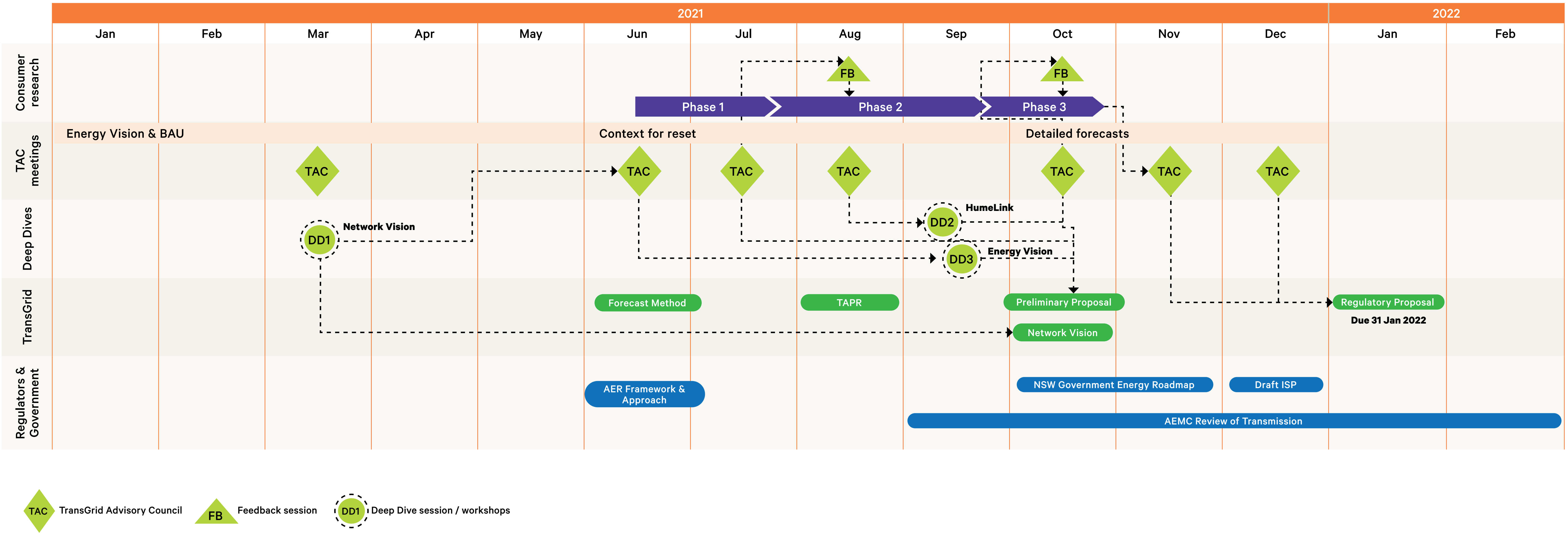
Stakeholder perception survey

We undertake an annual stakeholder perception survey, which has helped to shape our engagement approach for the regulatory reset.

We welcome your input and feedback on our Preliminary Revenue Proposal

We invite stakeholders to provide their feedback on this Preliminary Revenue Proposal by **26 October 2021** to revenue.reset@transgrid.com.au. We will share your feedback online unless you specifically request us not to.

We will engage further in November and December 2021 to explain what we have heard and how we have reflected it in our Revenue Proposal, which we will submit to the AER by 31 January 2022. We will continue to engage with stakeholders throughout 2022, and will reflect your input into our Revised Revenue Proposal, which we will submit in late 2022. You can also engage with the AER through its consultation processes on our proposals.



4. Our performance

We deliver the outcomes our customers value most – a safe, secure, reliable and affordable energy supply, while leading Australia's transition to net zero emissions.

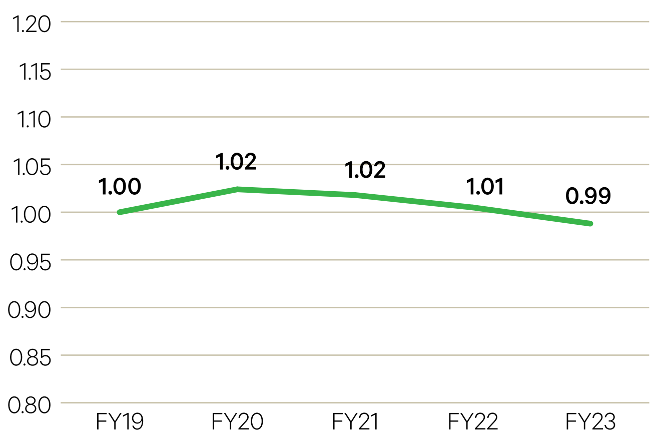
1 Safety is our top priority

The safety of our communities, customers, employees and delivery partners is our top priority. We maintain safety outcomes by managing our network risk.

Our total network risk is measured using a 'risk index', which is a multi-dimensional measure for safety, environmental, bushfire and reliability risk.

Figure 4.1 shows that by the end of the current period we expect our network risk index to be in line with the risk index at the start of the regulatory period. We have achieved this by continually reviewing and reprioritising our works programs to focus on the delivery of key projects driven by our compliance obligations.

Figure 4.1: Network Risk Index



2 We provide a secure and reliable supply

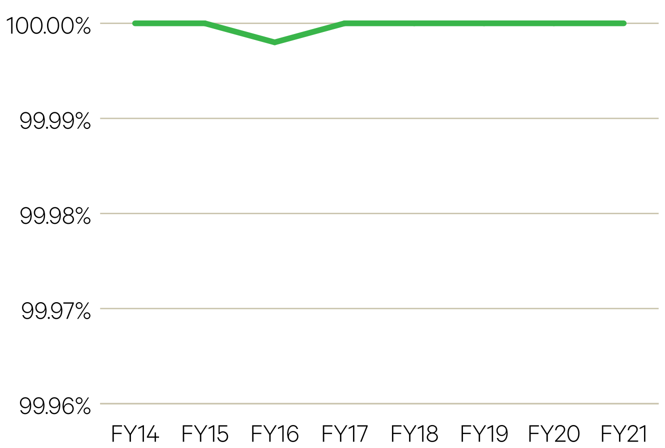
We manage the stability of the power system to ensure that electricity is delivered safely, securely and reliably to homes and businesses across NSW and the ACT.

Our reliability and performance standards are set out in our transmission licences[15], issued under the Electricity Supply Act 1995 (NSW) and Utilities Act 2000 (ACT).

Figure 4.2 shows that we have maintained a consistently high level of reliability over the current regulatory period, notwithstanding the emergencies we have experienced, including:

- the 2019-20 bushfires, which were the worst in NSW's history and caused unprecedented network damage
- 'One in 100-year' flooding in March 2021, which affected many of our assets, and
- extreme wind events between March 2019 to December 2020, which caused our transmission structures to collapse in six separate events.

Figure 4.2: Network reliability



15 Transmission operator's licence under the Electricity Supply Act 1995 (NSW).

3 Affordability for all Australians

Our investments in major ISP projects including QNI Minor, VNI Minor, and Project EnergyConnect will reduce customers' final electricity bills by helping to share reliable generation resources across the NEM, improve wholesale market competition, open-up the development of Renewable Energy Zones (REZs) and facilitate the development of large scale storage:

- Project EnergyConnect[16] will deliver annual residential savings for NSW customers of up to $64 p.a.[17]
- QNI Minor is expected to deliver approximately $170 million in net benefits[18] and VNI Minor is expected to deliver approximately $268 million[19] in net benefits. These net benefits will also contribute to total residential and business electricity bill reductions.

Project EnergyConnect delivers annual residential **savings** of up to

$64 p.a.

4 We have delivered opex efficiencies

We are using 2021–22 opex as the basis of our opex forecast in the next period and have removed our expenditure on bushfires from this base year.

We expect our actual opex in our 2021-22 base year to be $34.1 million below the AER's opex allowance (excluding debt raising costs), reflecting the operational efficiencies we have achieved. Over the 2023–28 regulatory period this equates to a saving of $170 million[20] to our customers, reflected in lower prices.

Customer **efficiency saving**

$170M

Efficiencies driven by:

- More effective labour utilisation
- Operating model changes
- Continually adapting our labour force to meet our ongoing needs
- Replacing manual and outdated processes and systems
- Improved work planning and scheduling.

16 FTI Consulting, Benefits of project EnergyConnect, June 2020.
17 Assuming: (i) wholesale price changes; (ii) the cost of EnergyConnect; and (iii) the effect of the Project on existing interconnector residues, are fully passed on to consumer retail bills, and average annual household consumption figures remain constant over time.
18 TransGrid and PowerLink, Project Assessment Conclusions Report, Expanding NSW-QLD transmission transfer capacity, 20 December 2019, p. 4. Net benefits are calculated over the period to 2044-45 (in NPV terms).
19 AEMO, Victoria to New South Wales Interconnector Upgrade, Project Assessment Conclusions Report, February 2020, p.6. Net benefits are calculated over the period to 2044-45 (in NPV terms).
20 Calculated by multiplying the base year underspend of $34.1 million by five years ($34.1m x 5 years = $170m).

5 We are efficient

We benchmark strongly against our peers. The AER's benchmarking, and the independent analysis that we have commissioned from HoustonKemp, show that we are amongst the most efficient TNSPs on a state-by-state basis on a range of measures. We rank:

- first in total cost per MVA of maximum demand served
- second in total cost per end user
- second in total cost per circuit length (per kilometre), and
- second on total cost per MWh of energy transported. Our costs on this measure have trended down since 2013-14 and our cost per MWh of energy has decreased by seven per cent since 2013-14.

Figure 4.3: Total cost per MVA of demand served

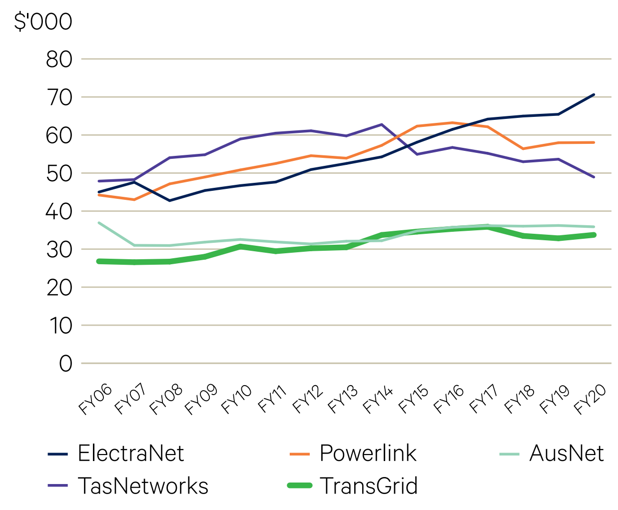


Figure 4.4: TNSP total cost per end user

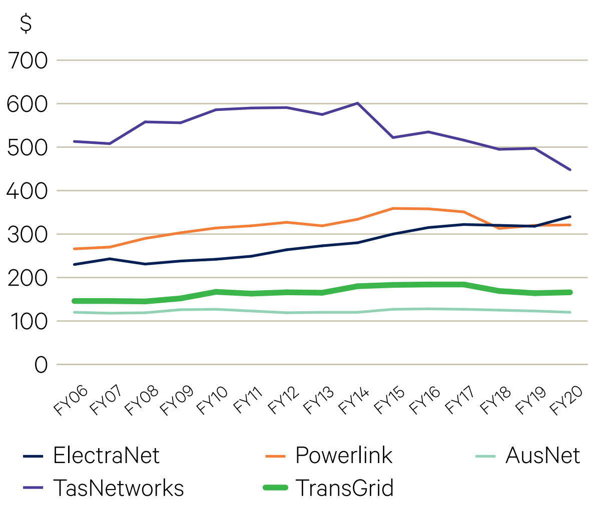


Figure 4.5: Total cost per circuit length (per km)

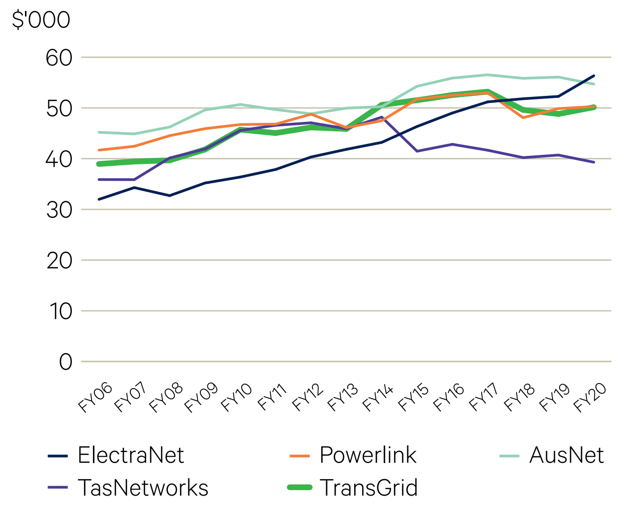
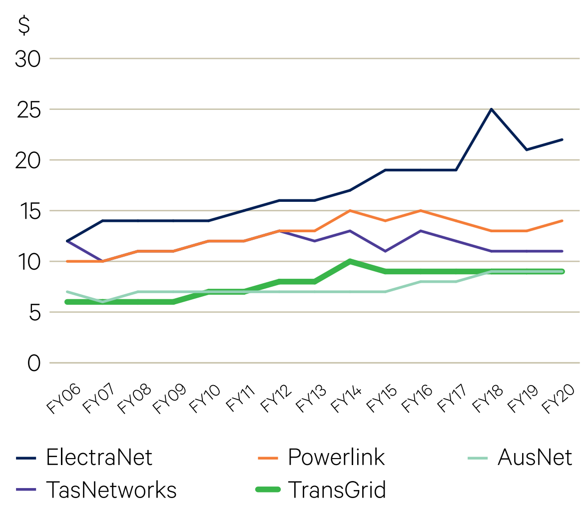
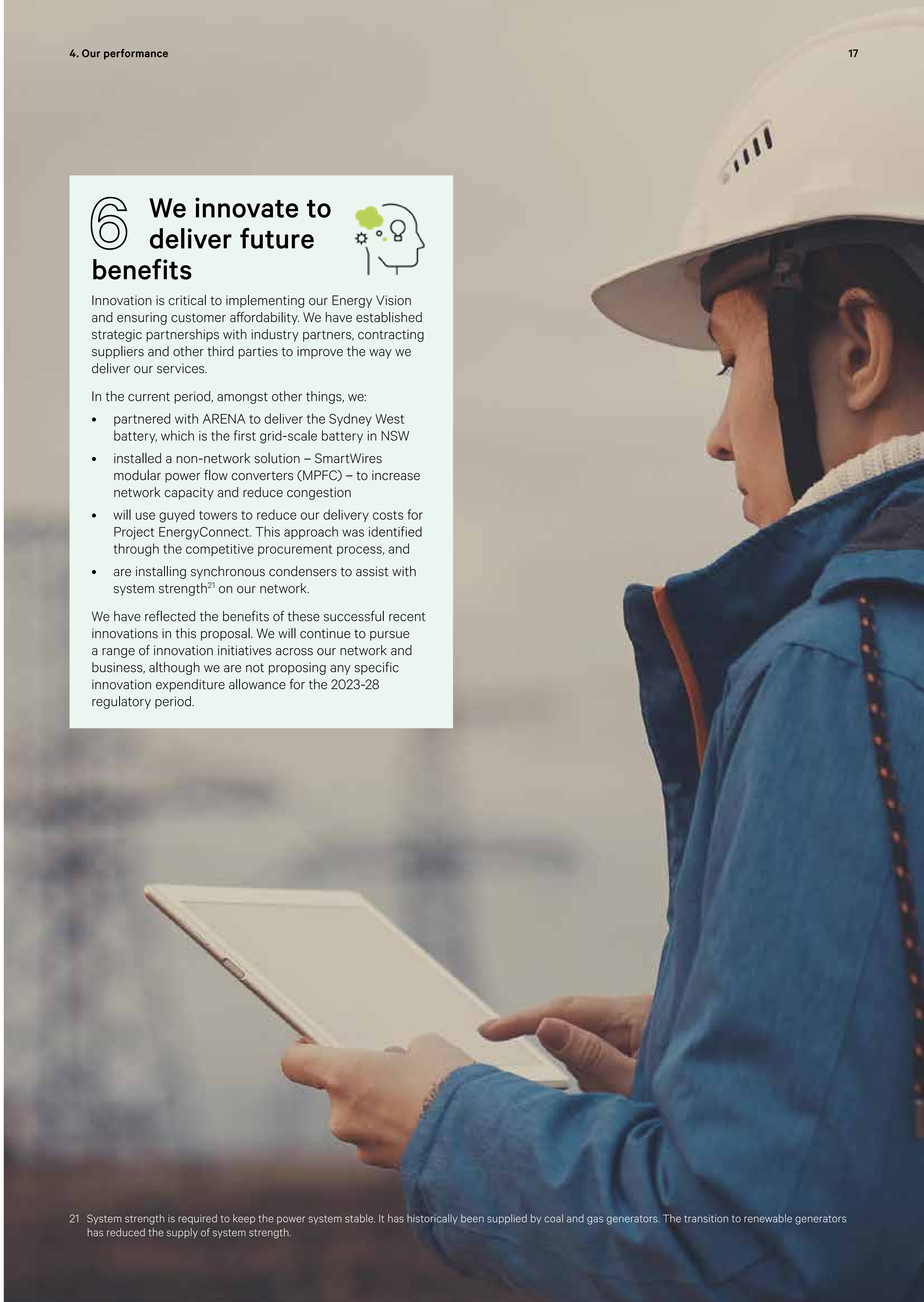


Figure 4.6: TNSP total cost per MWh of energy transported





6 We innovate to deliver future benefits

Innovation is critical to implementing our Energy Vision and ensuring customer affordability. We have established strategic partnerships with industry partners, contracting suppliers and other third parties to improve the way we deliver our services.

In the current period, amongst other things, we:

- partnered with ARENA to deliver the Sydney West battery, which is the first grid-scale battery in NSW
- installed a non-network solution – SmartWires modular power flow converters (MPFC) – to increase network capacity and reduce congestion
- will use guyed towers to reduce our delivery costs for Project EnergyConnect. This approach was identified through the competitive procurement process, and
- are installing synchronous condensers to assist with system strength[21] on our network.

We have reflected the benefits of these successful recent innovations in this proposal. We will continue to pursue a range of innovation initiatives across our network and business, although we are not proposing any specific innovation expenditure allowance for the 2023-28 regulatory period.

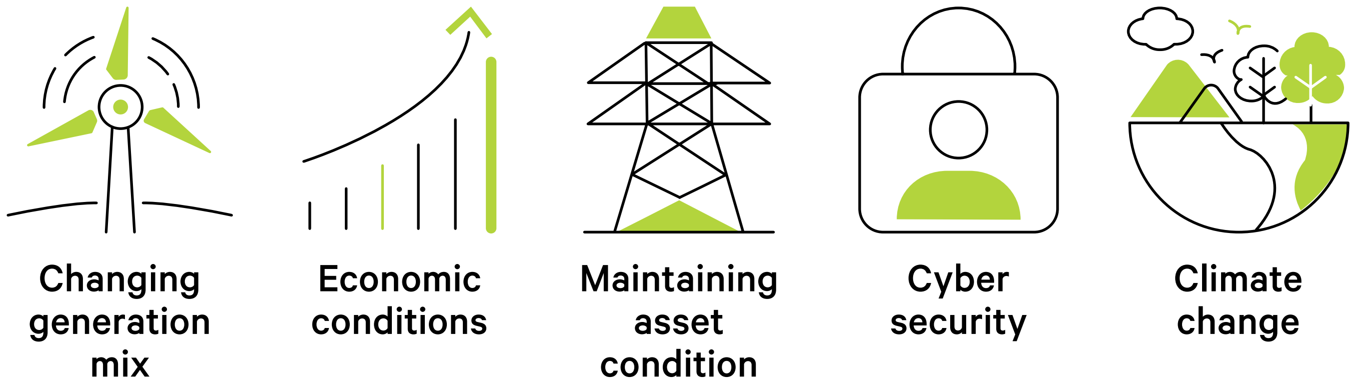
21 System strength is required to keep the power system stable. It has historically been supplied by coal and gas generators. The transition to renewable generators has reduced the supply of system strength.

5. Key operational challenges

The continued transformation of the power system presents unique challenges for our network operations.

Figure 5.1 details our key operational challenges in the coming period.

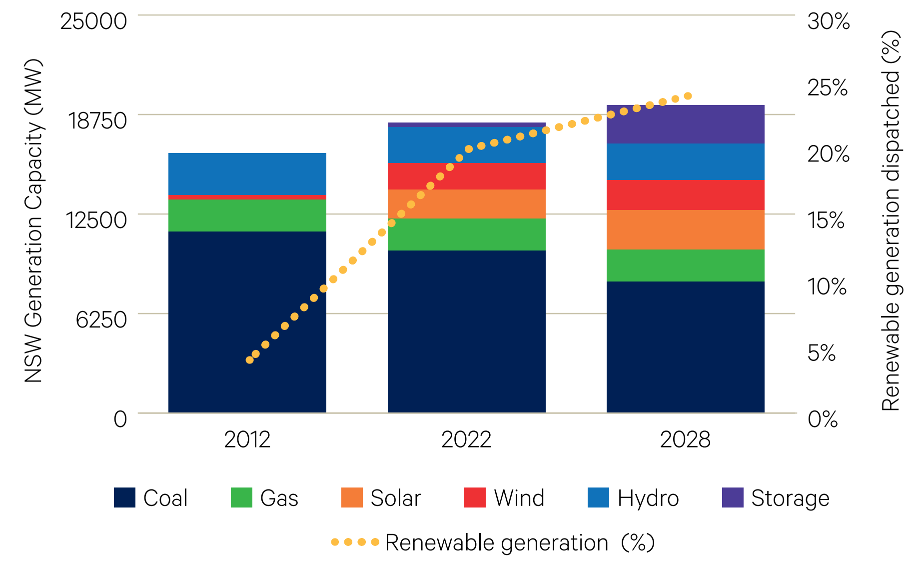
Figure 5.1: Key operating environment challenges



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 change in the generation mix is increasing the operational complexity of maintaining network stability and security. This includes increased power transfers leading to voltage management issues, more widespread network congestion, increasing fault levels in southern NSW and decreasing minimum demand due to increased solar generation. We must continue to invest, and work with AEMO, to address these issues.

Figure 5.2: NSW generation capacity and proportion of dispatched renewables

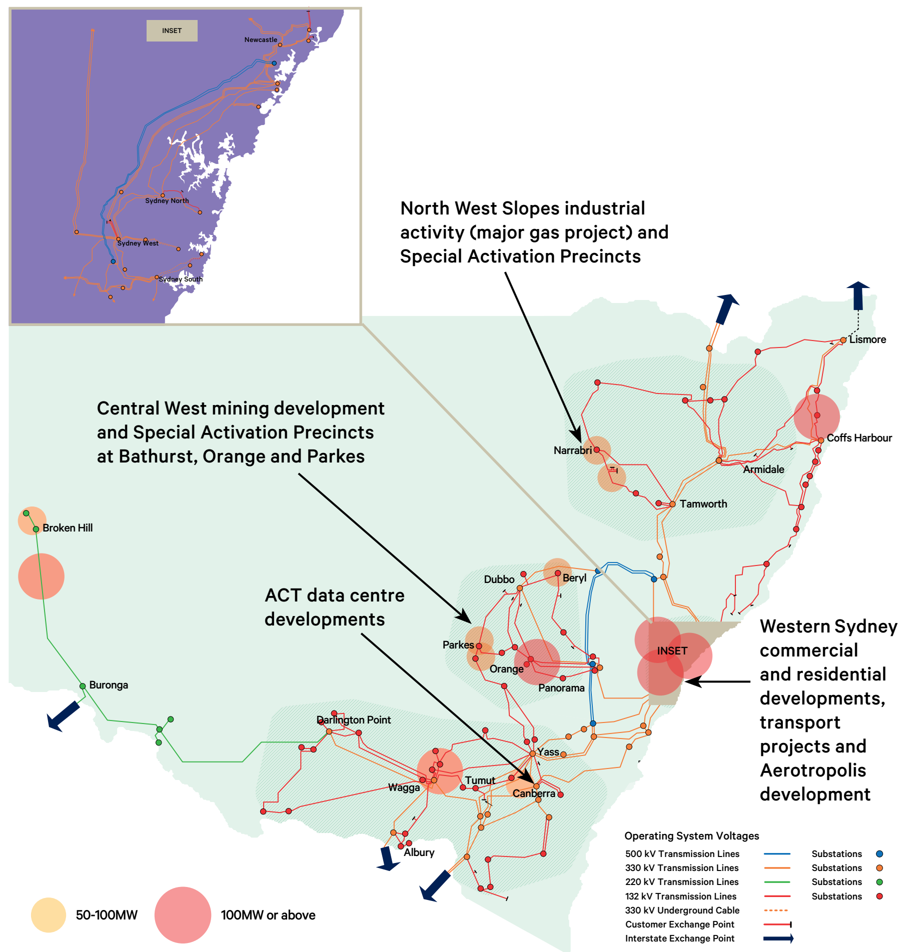


Economic conditions

Economic growth in NSW is forecast to return to trend over the next decade after the COVID downturn, with pockets of strong maximum demand growth expected in some regions, including the North West Slopes, central west and western Sydney.

Network investments are needed to address this load growth and to comply with mandated voltage and thermal stability limits and reliability standards.

Figure 5.4: Future spot loads in NSW



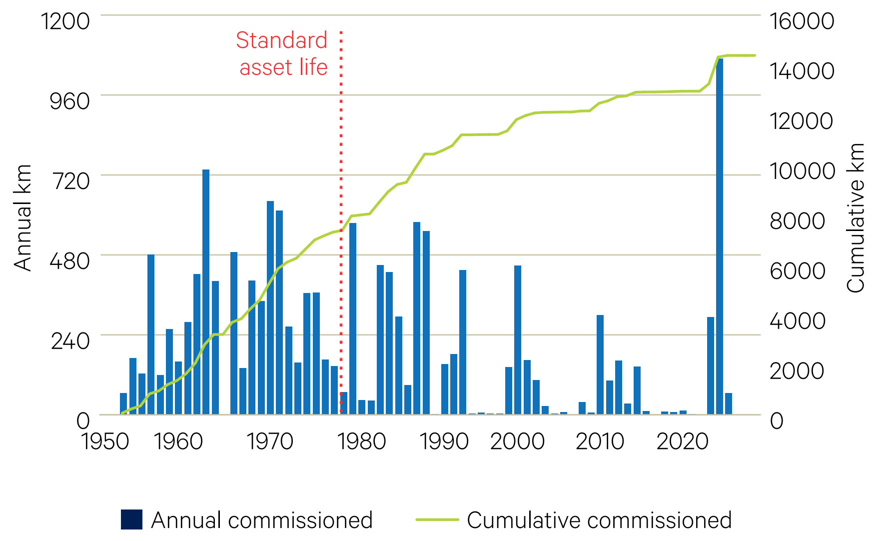
Maintaining asset condition

Our asset base is continuing to age and decline in condition with increasing deteriorated and obsolete assets – 40 per cent of our network was commissioned before 1970. Age related asset failures are exacerbated by more frequent and damaging severe weather events.

We must invest to maintain the long-term condition of our assets, particularly our transmission lines and digital infrastructure, in order to manage our network risk and maintain our performance.

We forecast that cost of materials will increase at a rate faster than CPI, however to address our customers' concerns regarding affordability, we have not included a real increase in materials costs for the 2023-28 regulatory period.

Figure 5.5: Transmission network age profile



Cyber security

The Australian Government is introducing new obligations that we will need to comply with during the next regulatory period to:

- ensure that our network is protected against cyber and physical infrastructure threats, and
- maintain the security and reliability of our network expected by our customers.

New cyber and physical security obligations:

Security of Critical Infrastructure Act 2018

Security Legislation Amendment (Critical Infrastructure) Bill 2020, introduced to Federal Parliament on 10 December 2020

the Federal Government is considering a proposal to introduce an enhanced regulatory framework that will increase our security and resilience requirements

Climate change

The frequency, intensity and duration of climate-driven extreme weather events are increasing.[22] Over the current regulatory period, we experienced a marked increase in these events impacting our network, including bushfires, storms and extreme winds and floods.

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. We are already responding to climate change by replacing assets with more resilient alternatives when we undertake planned condition-based replacements, such as replacing deteriorated timber poles with concrete or steel poles.

GHD's independent climate change adequacy review of our network found that we are leaders in assessing and implementing options to improve our network resilience to climate change.

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

6. Preliminary capex forecast

Our proposed capital expenditure (capex) is needed to transform our network, address our operational challenges and maintain safety, security and reliability.

Important note

In the 2018-23 regulatory period, the AER approved capex of **$1,978.7 million**[23] for Project EnergyConnect. We expect to spend **$500 million** of this in the 2023-28 period. We refer to this as pre-approved 2023-28 capex.

In the 2023-28 period, we expect to deliver actionable ISP Projects identified in AEMO's optimal development path, including HumeLink. These ISP projects will be determined by AEMO in its ISPs, which it issues every two years. AEMO's 2022 ISP will be finalised in June 2022, with a draft issued in December 2021. Subject to confirmation in the ISP, we will progress these projects under the Actionable ISP Rules.

Our 2023-28 preliminary forecast capex excludes both pre-approved 2023-28 capex and any further capex for Actionable ISP projects arising from the 2022 ISP.

Our preliminary 2023-28 forecast capex of $1,439 million is $89 million or 7 per cent higher than our estimated capex of $1,350 million for the 2018-23 regulatory period. Our capex for the 2023-28 regulatory period is needed to maintain a safe, secure and reliable network that supports the changing energy system and addresses the operational challenges we are facing.

We have excluded from our expected capex in 2018-23 the AER's $1,768.6 million allowance on actionable ISP Projects, which it approved as contingent projects for the 2018-23 regulatory period (i.e. Project EnergyConnect, QNI Minor and VNI Minor). This enables us to compare our underlying (i.e. non-ISP) estimated capex for 2018-23 and our forecast capex for the 2023-28 period.

Table 6.1: Comparison: 2018-23 actual and 2023-28 forecast capex, excluding ISP project ($M)

Capex by sub-category	Total 2018-23	Total 2023-28
Replacement expenditure (Repex)	756.8	786.5
Augmentation expenditure (Augex)	301.3	332.5
Information and communication technology (ICT)	94.3	86.9
Property	12.8	20.8
Fleet, plant and equipment	42.6	47.9
Capitalised overheads	142.4	164.4
Total	**1,350.2**	**1,439.0**

23 Excluding equity raising costs.

Figure 6.1: 2023-28 forecast capex by subcategory

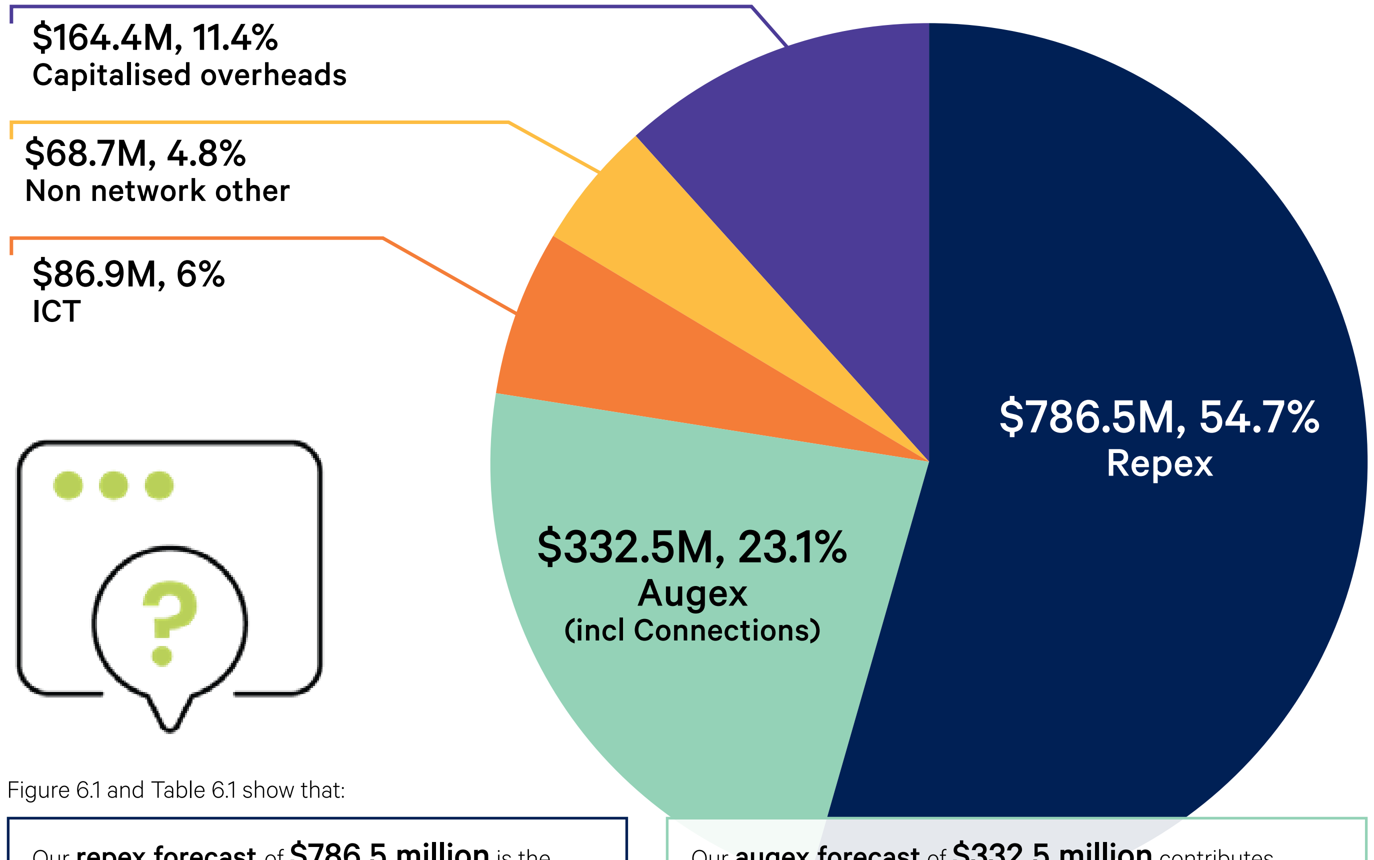


Figure 6.1 and Table 6.1 show that:

Our **repex forecast** of **$786.5 million** is the largest component **54.7 per cent** of our proposed total capex and will increase slightly **3.9 per cent above** our current period expenditure to deliver a safe and reliable network as our network ages and condition-related issues increase. We must also invest to enhance our cyber and physical security capability and respond to the changing generation mix.

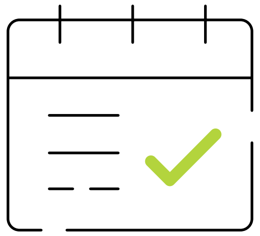
Our **augex forecast** of **$332.5 million** contributes **23.1 per cent** of our proposed total capex and is about **10.4 per cent higher** than our estimate for the current period. The key drivers of this increase are addressing rapid localised load growth and spot loads, maintaining compliance, including with fault-levels and voltage stability, and realising economic benefits by enabling additional low cost and low emissions generation.

Our **ICT capex forecast** of **$86.9 million** is **7.8 per cent lower** than our estimate for the current period, and will enable us to rollout new technology and continue to refresh or replace legacy applications and systems at the end of their lives.

Our **non-network other capex forecast** of **$68.7 million** is **24.0 per cent higher** than our estimate for the current period as we continue to provide safe, compliant and productive offices and depots to support the increase in our network operations activity and invest to maintain the suitability and safety of our fleet, plant and equipment.

Our **capitalised overheads forecast** of **$164.4 million** is **15.4 per cent higher** than our estimate for the current period to enable us to deliver a larger capital works program.

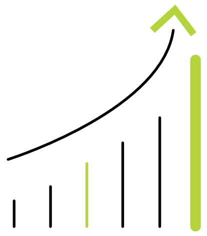
Figure 6.2 shows that:



Over the 2018-23 regulatory period, we expect our actual capex of

$1,350 million,

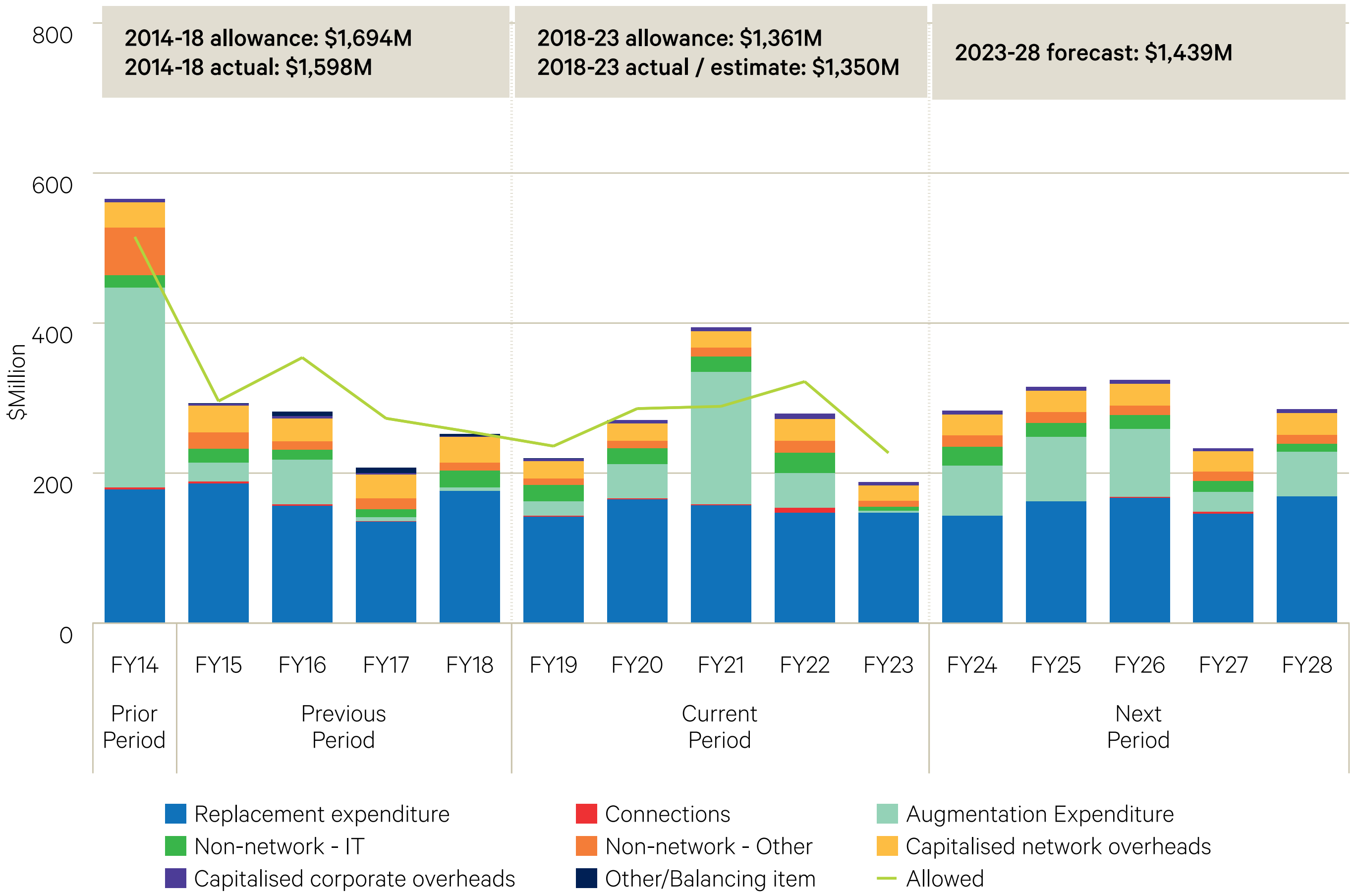
excluding ISP Projects, to be in line with the AER's allowance of **$1,361 million**.

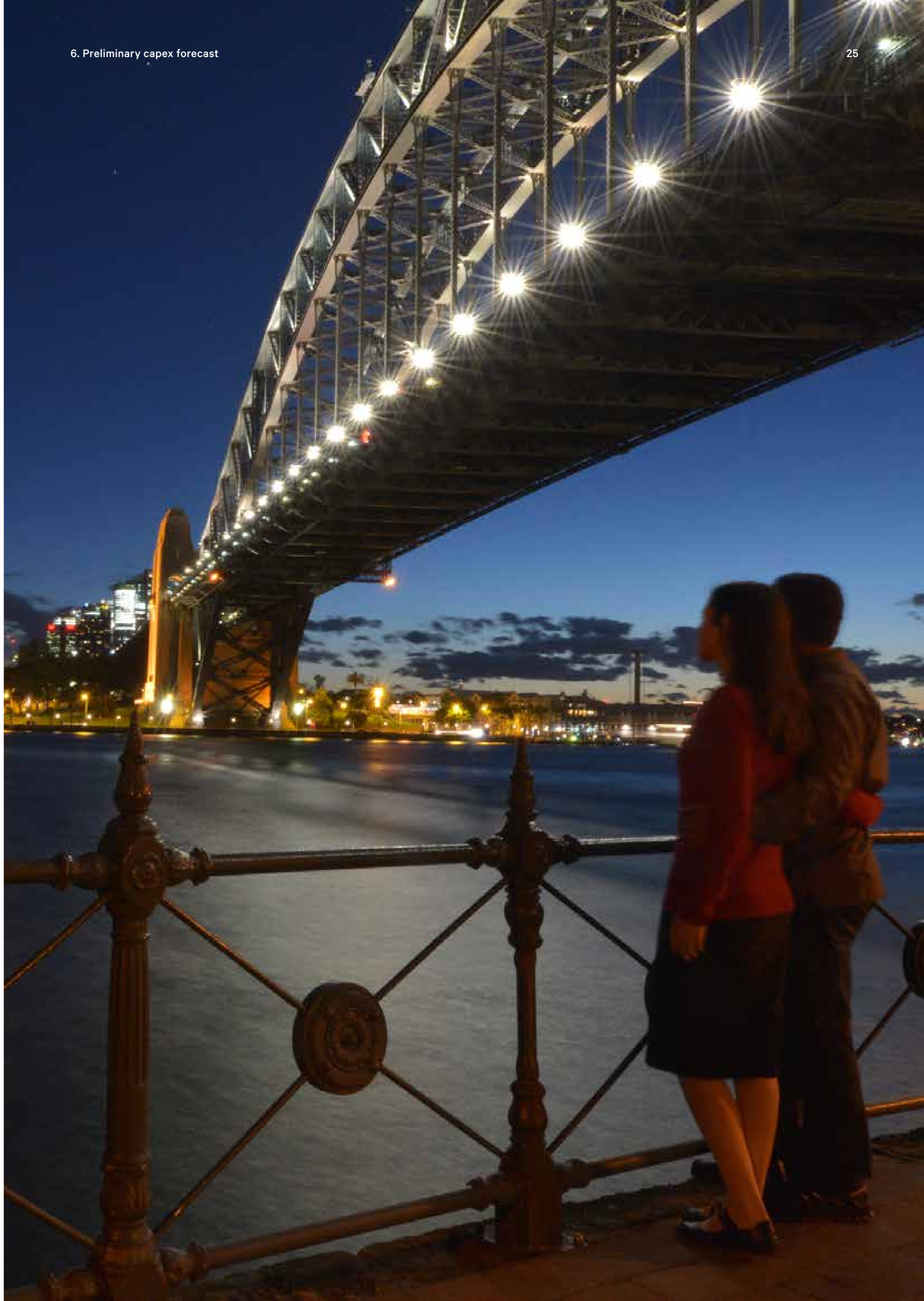


Our forecast 2023-28 capex of

$1,439 million, excluding pre-approved 2023-28 capex, is **$89 million** or **7 per cent** higher than our estimated capex of **$1,350 million** for the 2018-23 period.

Figure 6.2: Capex trends compared to the AER allowance, excluding pre-approved capex and ISP Projects





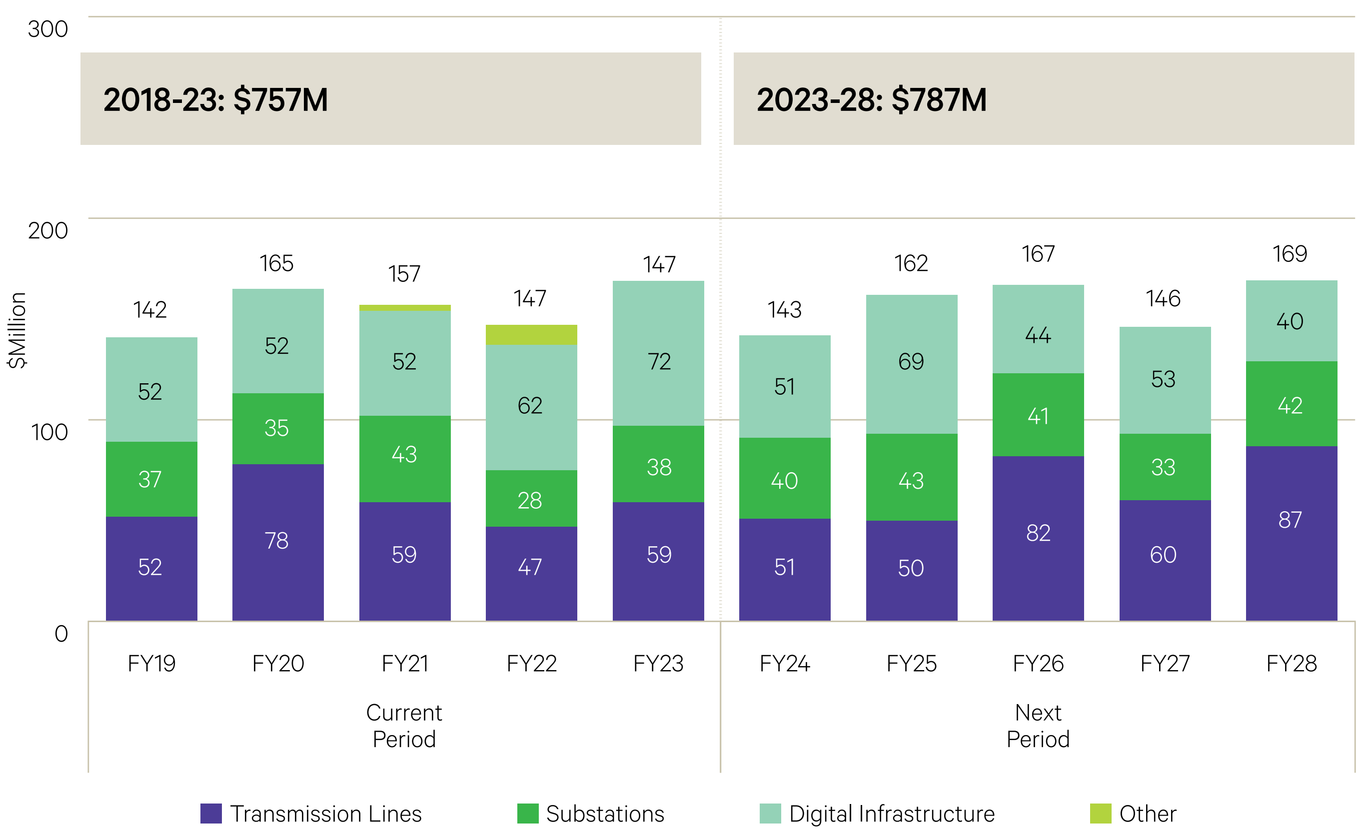
Repex

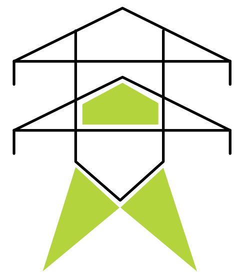
Our 2023-28 repex forecast of **$787 million** is **4 per cent above** our estimated 2018-23 repex of **$757 million** and is required to deliver a safe and reliable network as our network ages and condition-related issues continue to grow. We will replace and upgrade deteriorated and obsolete assets using a risk-based approach to maintain asset condition and risk. Investment is required to improve the cyber security of our digital and physical network infrastructure to meet new requirements, which are expected to become mandatory during the next regulatory period.

We will continue to address climate change and promote network resilience to maintain our network safety, reliability and security, as we experience more frequent extreme climate-driven natural hazard events. We will also continue to adopt innovation-driven practices and approaches to our repex, to ensure customer costs reflect efficient levels of investment.

Our repex forecast comprises three major categories – transmission lines, digital infrastructure and substations. Our repex is supported by asset condition data, quantified risk assessments and economic evaluations.

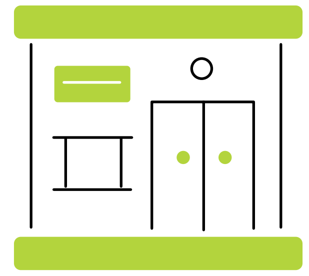
Figure 6.3: Comparison of repex by sub-category in current and next regulatory period





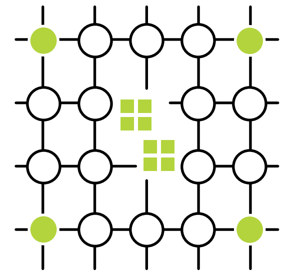
Transmission lines

Our 2023-28 repex forecast of **$330.1 million** is required to maintain the safety and reliability of the network to meet our compliance obligations as the condition of our transmission line assets deteriorates. This repex is needed to promote network resilience in response to extreme weather events and asset aging.



Substations

Our repex forecast for substations of **$199.7 million** is required to maintain the safety and reliability of the network, as condition-related issues and the average age of the legacy assets continues to grow.



Digital infrastructure

Digital infrastructure assets include protection and control equipment, communications and metering equipment, and their associated power supplies. These assets monitor each network element and take automatic action in the event of faults and other events. They also provide real time monitoring and remote operation capability allowing us to efficiently operate our network. Our 2023-28 repex forecast of **$256.7 million** is required to maintain the safety and reliability of the network as operational complexity of the network increases, technology changes and new legislative requirements for cyber and physical security are introduced.

Augex

Our 2023-28 augex forecast of **$332.5 million**[23] is about **10 per cent above** our estimated 2018-23 augex of **$301.3 million** and is required to:

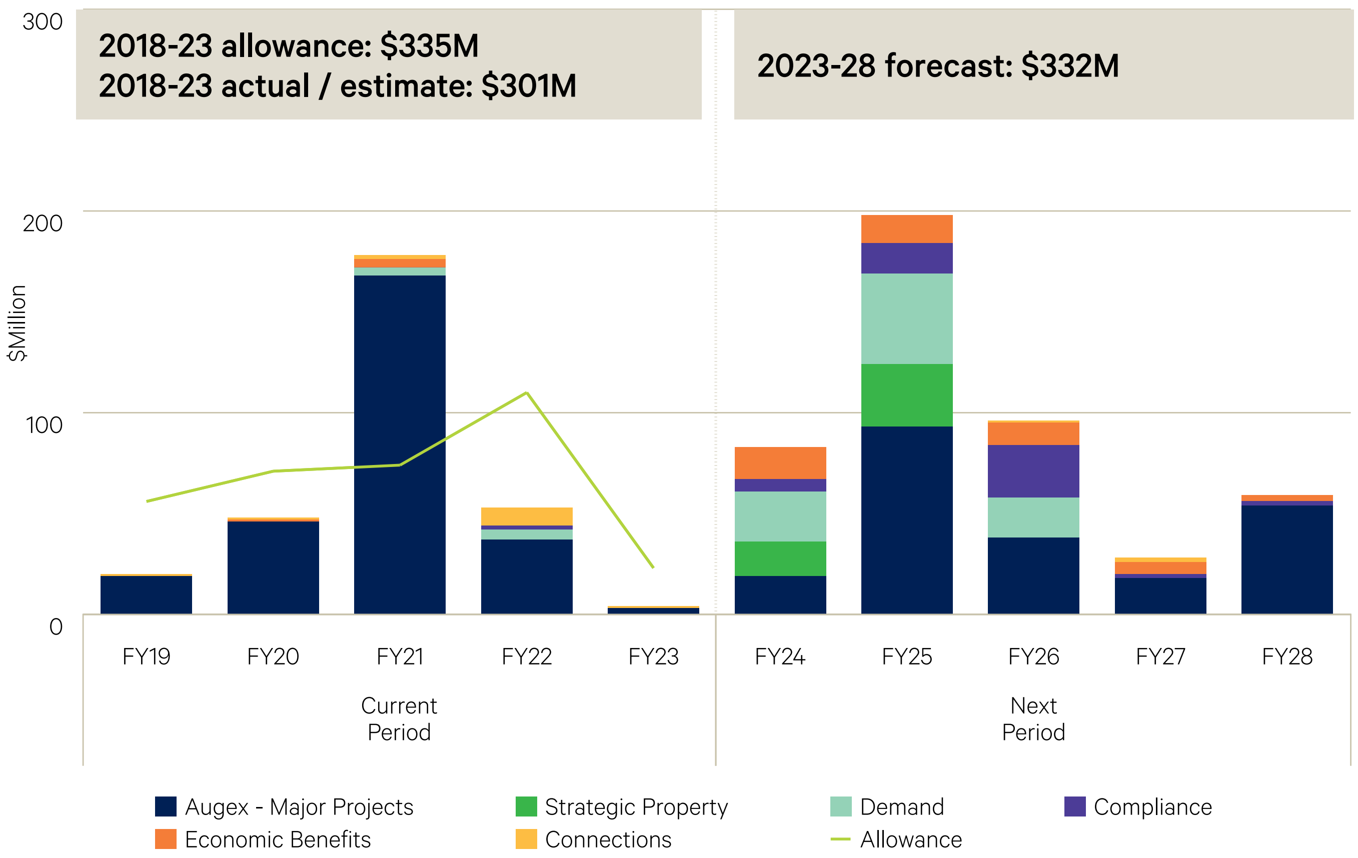
- support rapid load growth driven by new spot loads including data centres and large commercial and residential developments in western Sydney (Sydney Priority Growth area). Peak demand increases are also forecast for the Beryl and Vineyard (north-west Sydney) areas
- meet our compliance obligations relating to fault levels in southern NSW, voltage stability impacts and power quality issues resulting from the development of renewable energy projects throughout NSW as the minimum demand for NSW is forecast to decline over the next regulatory period, and
- invest to realise economic benefits arising from additional generation from low cost and low emission sources.

Projects are identified by comparing the avoided risk cost or economic benefits against the cost of the credible options using an economic cost-benefit evaluation. This ensures our investments are prudent and efficient.

We will also identify projects that can be funded under the Network Capability Incentive Parameter Action Plan (NCIPAP), which is the network capability component of the AER's Service Target Performance Incentive Scheme (STPIS).

Figure 6.4 shows the trend in our expected and forecast augex.

Figure 6.4: Comparison of augex in current and next regulatory period



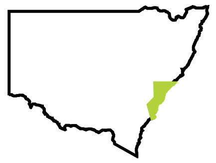
23 Excluding pre-approved 2023-28 capex.

Major Projects (Non-ISP)

Major Projects are non-ISP augex projects greater than $40 million. These projects comprise around $119.5 million or 36 per cent of our forecast augex, which are required to:

- respond to locational load growth which if not addressed will lead to non-compliance with National Electricity Rules' (NER or Rules) voltage limits and IPART's reliability standards due to voltage stability and thermal limitations, and
- improve fault level ratings to ensure compliance with NER obligations.

Major Projects, drivers and forecast capex

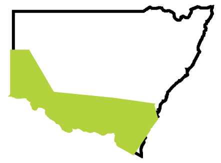


Supply to Western Sydney Priority Growth area

$71.1 million

Driver: Locational demand

Driven by substantial increase in spot load in the Sydney Priority Growth area around the Western Sydney Aerotropolis, metro train lines, data centres and large commercial and residential developments and the need to maintain the reliability and supply capability to Endeavour Energy's Western Sydney distribution network.



Improve fault levels in Southern NSW

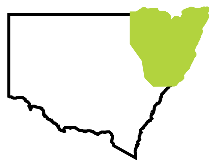
$48.4 million

Driver: Compliance

Required to upgrade fault levels in Southern NSW to ensure NER compliance[24] with equipment fault level ratings. This investment is a consequence of various major ISP projects, as well as the development of Snowy 2.0 and the increase in the connection of renewable generation in the area.

We have not included the following projects in our forecast at this stage because they are currently undergoing a regulatory investment test for transmission (RIT-T). We will include the preferred option identified through the RIT-Ts in our augex forecast in our Revised Revenue Proposal.

Major Projects undergoing a RIT-T



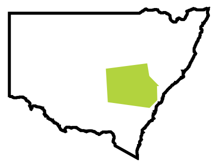
Supply to North West Slopes Area project[25]

Indicative cost: $155 million

Driver: Locational demand

Driven by increased spot load resulting from the connection of new industrial loads (i.e. Narrabri Gas) and underlying demand growth in Narrabri and Gunnedah. If not addressed, this load increase will lead to non-compliance with NER voltage limits[26] and IPART reliability standards due to thermal limitations.

The RIT-T can be found here.



Supply to Bathurst Orange and Parkes (stage 1)[27]

Indicative cost: $107 million

Driver: Locational demand

Driven by increased spot load due to the expansion of a mine at Orange, connection of new mines in the Bathurst and Parkes areas and industrial load expansion at the Parkes special activation precinct. If not addressed, this load increase will lead to non-compliance with NER voltage stability limits[28]. Stage 1 investment involves the installation of dynamic reactive power support devices at Parkes and Panorama substations.

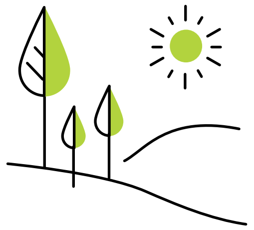
The RIT-T can be found here.

24 NER Clauses 4.2.2(d), 4.3.4. 4.6.1(b)(1) and 4.6.2 requires equipment not be exposed to fault current exceeding its rating.
25 The Project Specification Consultation Report (PSCR) was published in April 2021. The Project Assessment Draft Report (PADR) is expected to be published in late 2021.
26 Schedule 5.1.4 of the NER requires us to plan for voltage control to maintain voltage levels within 10 per cent of normal voltage.
27 The PSCR was published in March 2021. The PADR is expected to be published in late 2021.
28 Schedule 5.1.4 of the NER requires us to plan for voltage control to maintain voltage levels within 10 per cent of normal voltage.

Strategic property

Strategic property relates to the acquisition of easements for future investments to meet expected load growth and deliver future ISP Projects, which would support the transition to renewable generation. We have included the following strategic property project in our augex forecast:

2023-28 strategic property – included in augex forecast



Strategic property acquisition for Western Sydney Priority Growth area

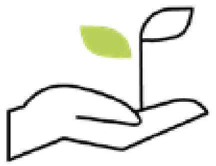
$17.1 million

A new Western Sydney bulk supply point (BSP) will be required to supply the growing Western Sydney demand. Land south of the existing Kemps Creek 500/330 kV Substation is a suitable site with its access to the 330 kV and 500 kV network and its 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.

2023-28 strategic property – included in contingent projects

We have not included the following strategic property project in our augex forecast. At this stage, we have included it as a contingent project and will reassess its status for our Revenue Proposal once we understand how AEMO is treating this project in its 2022 Draft ISP.



Strategic easement acquisition for supply to Sydney from the south

This easement will provide a corridor for a future 500 kV double circuit transmission line to be installed from South Creek to Bannaby. It is required for the 'Reinforcing Sydney, Newcastle and Wollongong Supply' project, which is a future project in AEMO's 2020 ISP.

Base augex

Base augex relates to investments in compliance, demand and economic benefits. This investment comprises $193.1 million or 58.1 per cent of total augex. We are projecting an increase in the three categories of our base augex over the 2023-28 regulatory period.

Compliance

$51.9 million

The change in the generation mix is expected to lead to various voltage and fault level issues through the NSW network, requiring additional compliance-driven projects to maintain power quality. In addition, the minimum demand for NSW is forecast to decline over the next regulatory period, predominantly due to solar PV generation from households. This is expected to require the installation of reactors to maintain voltage stability. Key compliance related projects included in our base augex are:

- improve voltage control in Southern NSW area **$20.7 million**
- maintaining voltage in greater Sydney area **$8.9 million**

Demand

$91.0 million

Anticipated load growth is also driving an increase in base augex, outside of the Major Projects, including to:

- maintain voltage in the Beryl area **$20.7 million**
- supply to Sydney west area **$17.2 million**
- supply to far west NSW **$15.2 million**

Economic benefits

$50.1 million

The increase in renewable generation across the network is leading to increases in generator constraints in some areas. Investment to relieve these constraints will reduce generator curtailment and provide an economic benefit by enabling additional generation from these low cost and low emission sources. The most substantive economic benefits projects included in our base augex are:

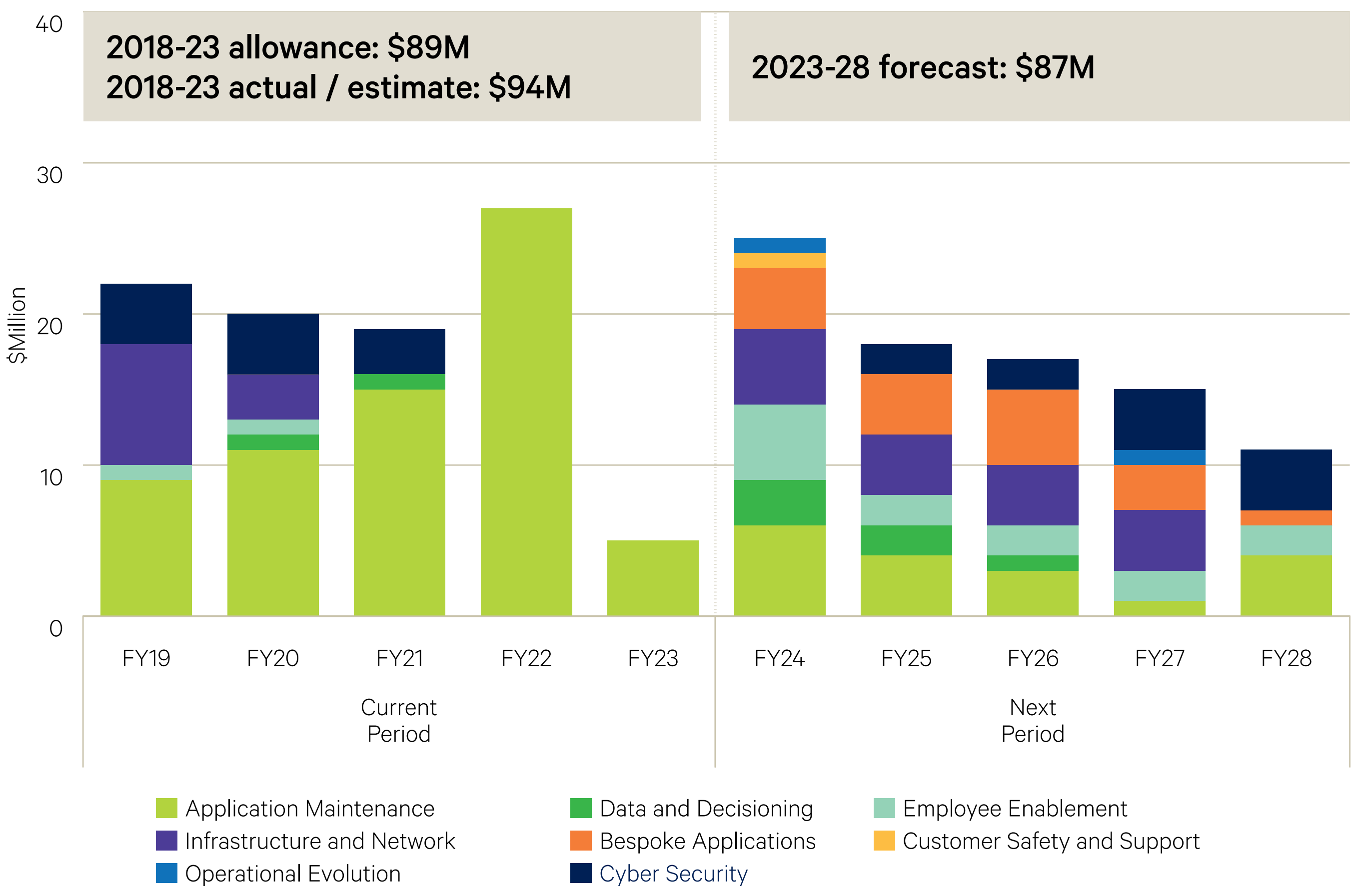
- increase capacity of 132 kV busbars at Wagga Wagga Substation **$10.5 million**
- increase capacity for generation in Wagga Wagga North area **$9.9 million**

ICT

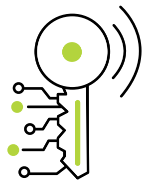
Our 2023-28 ICT forecast of **$87 million** is **$7 million**, or **8 per cent**, lower than our estimated 2018-23 capex of $94 million. This is due to changes in International Financial Reporting Standards (IFRS), which mean that in the 2023-28 period we will expense costs for configuration or customisation in cloud computing arrangements, whereas in the 2018-23 regulatory period these costs were treated as capex. Our 2023-28 ICT forecast is required to:

- refresh or replace legacy applications and systems which are at the end of life
- enhance our data analytics and reporting capability
- continue our transition to cloud-based platforms
- modernise our IT platforms to align with the changing requirements of our network and technology trends, and
- meet our obligations under new cyber security legislation.

Figure 6.5: Comparison of ICT capex in current and next regulatory period



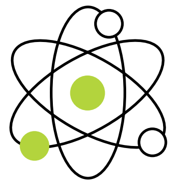
Our ICT capex forecast for the 2023-28 periods by package is.



Application maintenance

$18.2 million

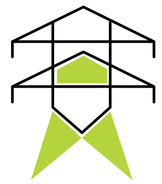
This investment is required to update or replace around 93 specialised software applications either due to obsolescence or end of vendor support.



Bespoke applications

$17.5 million

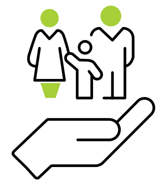
This investment involves refreshing our bespoke applications with a modern code base and implementing a secure development environment for all applications.



Data and decisioning

$6.3 million

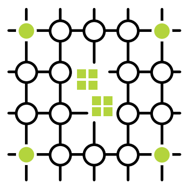
This investment is required to address gaps in our core data and inconsistent data flow which impacts our business operations and our customers.



Customer safety and support[29]

$1.0 million

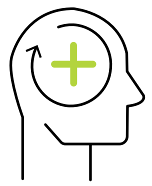
This investment is required to upgrade our Customer Relationship Management (CRM) system to support multi-channel engagement that will allow stakeholders self-service access to real time, tailored information.



Infrastructure and network

$17.8 million

This investment is required to undertake a cyclical refresh of our Corporate Data Network (CDN) and Data Centre (DC) to extend their asset lives.



Employee enablement

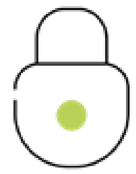
$12.2 million

This investment is required to introduce the Office 365 subscription model and migrate to Microsoft Exchange Online and SharePoint Online. It also involves replacing the soon to be decommissioned Integrated Services Digital Network (ISDN) telephony solution with a Session Internet Protocol (SIP) solution.

Operational evolution

$1.9 million

This investment is required to replace our Project and Portfolio Management (PPM) system with a hybrid cloud-based solution that incorporates the industry standards system.



Cyber security

$12.0 million

This investment is required to meet new cyber security and critical infrastructure compliance obligations.

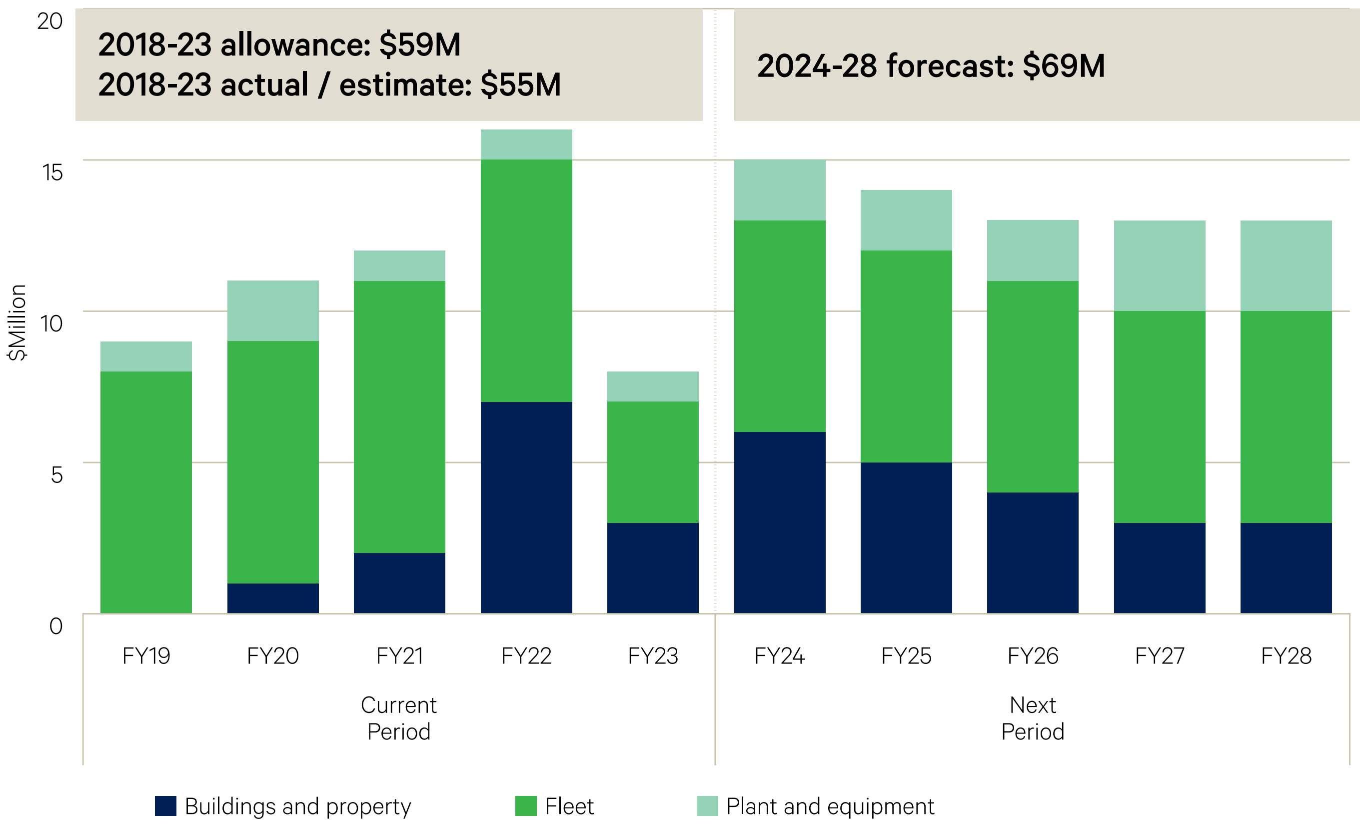
29 The application is expected to be fully delivered in FY26.

Non-network capex

Our 2023-28 Non-network capex forecast comprises property, fleet, and plant and equipment. Our forecast capex of **$68.7 million** is **24 per cent** above our estimated 2018-23 capex of **$55.4 million** and will enable us to continue to:

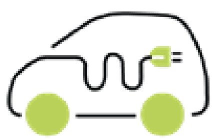
- deliver safe, compliant and productive offices and depots that support the increase in network operations activity as we deliver an increasing capital program including major ISP projects, and
- ensure our staff and contractors can safely access network sites and undertake required work so that we can continue to provide a reliable, secure and safe delivery of prescribed transmission services.

Figure 6.6: Comparison of Non-network capex in current and next regulatory period

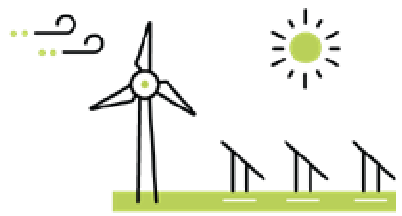


Property
$20.8 million

This investment is based on the outcome of an independent condition audit of our offices and depots. It will ensure that we maintain our depots to a safe and compliant standard.



Fleet
$35.9 million



Plant and equipment
$12.0 million

We apply an established risk management framework to determine our fleet, plant and equipment forecasts, which optimises cost, risk and performance while meeting our regulatory compliance obligations.

Capitalised overheads

Overhead activities support the delivery of our capital program. They include corporate support and management costs not directly incurred in producing output, and shared costs that we cannot directly allocate to a particular business activity or cost centre.

Our 2023-28 forecast of **$164 million** is **$22 million** or **15 per cent higher** than 2018-23 estimated capex of **$142 million** to enable us to deliver a larger capital works program.

We have forecast our overhead costs using the AER's default approach based on:

- 75 per cent of capitalised overheads are fixed at current levels, and
- 25 per cent of capitalised overheads vary with direct capex.[30]

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

7. Preliminary opex forecast

Our proposed operating expenditure (opex) is needed to support the growth in our network and meet the costs of external changes in the insurance market and cyber and physical infrastructure threats.

Our opex to manage our network includes inspections, asset maintenance and management, network operations, insurance, rates and taxes and corporate support functions.

Our total preliminary opex forecast for the 2023-28 regulatory period is **$1,109.6 million**, including debt raising costs[31]. This is **$205.2 million**, or **23 per cent higher** than our estimated opex for the 2018-23 regulatory period.

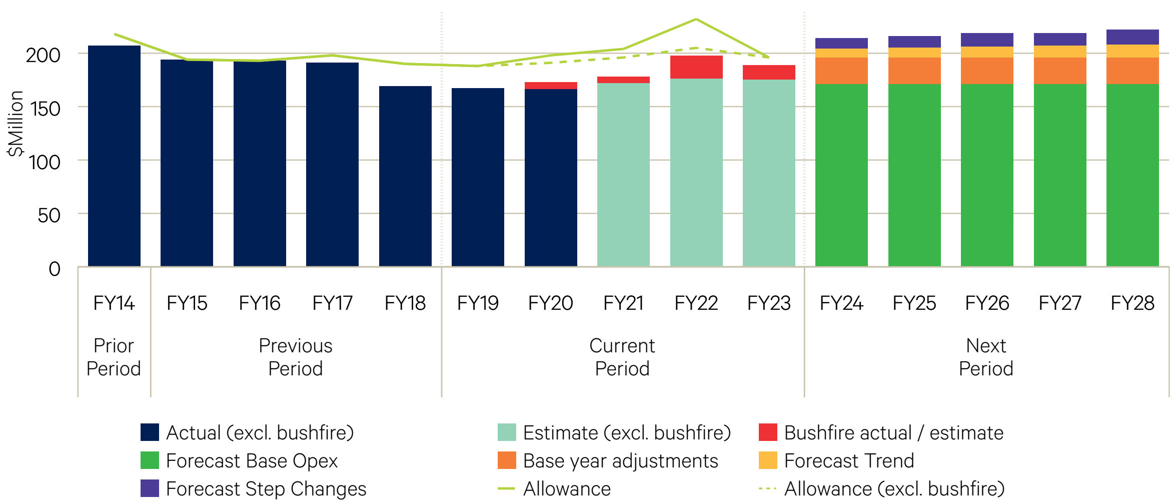
We have used the base-step-trend approach to prepare our opex forecast. We estimate our 2021-22 opex base year to be **$34.1 million below** the AER's opex allowance for this year[32], which reflects operational efficiencies.

The increase in our 2023-28 preliminary opex forecast is driven by:

- changes in accounting standards (international financial reporting standards (IFRS), so that for the 2023-28 period we expense ICT costs that were treated as capex in the 2018-23 period
- network growth over 2023-28 period – we expect our network to grow by around 8 per cent or 1,070km following the delivery of Project EnergyConnect, Powering Sydney's Future and Stockdill substation. We need to increase our opex to maintain these assets
- step-changes for additional externally driven costs in the 2023-28 period that are not in our base year opex. These relate to increases in insurance premiums, new cyber and physical security requirements and requirements to undertake ISP preparatory activities[33].

Figure 7.1 shows that we expect our 2018-23 opex of $904.7 million to be $113.6 million (or 11 per cent) below the AER's allowance[34] of $1,018.2 million, including the bushfire allowance (BFA) but excluding debt raising costs. Our efficiency savings relative to the AER's allowance show we are responding appropriately to the incentives under the regulatory framework, including the AER's Efficiency Benefit Sharing Scheme (EBSS).

Figure 7.1: Historical and forecast opex (excluded debt raising costs)



31 This includes debt raising costs of $23.7 million.
32 Excluding debt raising costs.
33 Under NER rule 5.10.2 preparatory activities include activities to design and investigate the costs and benefits of actionable and future ISP projects including detailed engineering design, route selection, easement assessment, cost estimation, stakeholder engagement and assessment of environmental and planning approvals.
34 Adjusted for AER approved cost pass through - 2019-20 Bushfire season bushfire allowance of $49.8m (nominal $). We incurred/expect to incur the costs FY20, FY21 and FY22 and be compensated for them in FY23, FY24 and FY25. For the purposes of meaningful comparison we have aligned the adjustment to the 2018-23 AER opex allowance of the pass through costs to when we have incurred / expect to incur them.

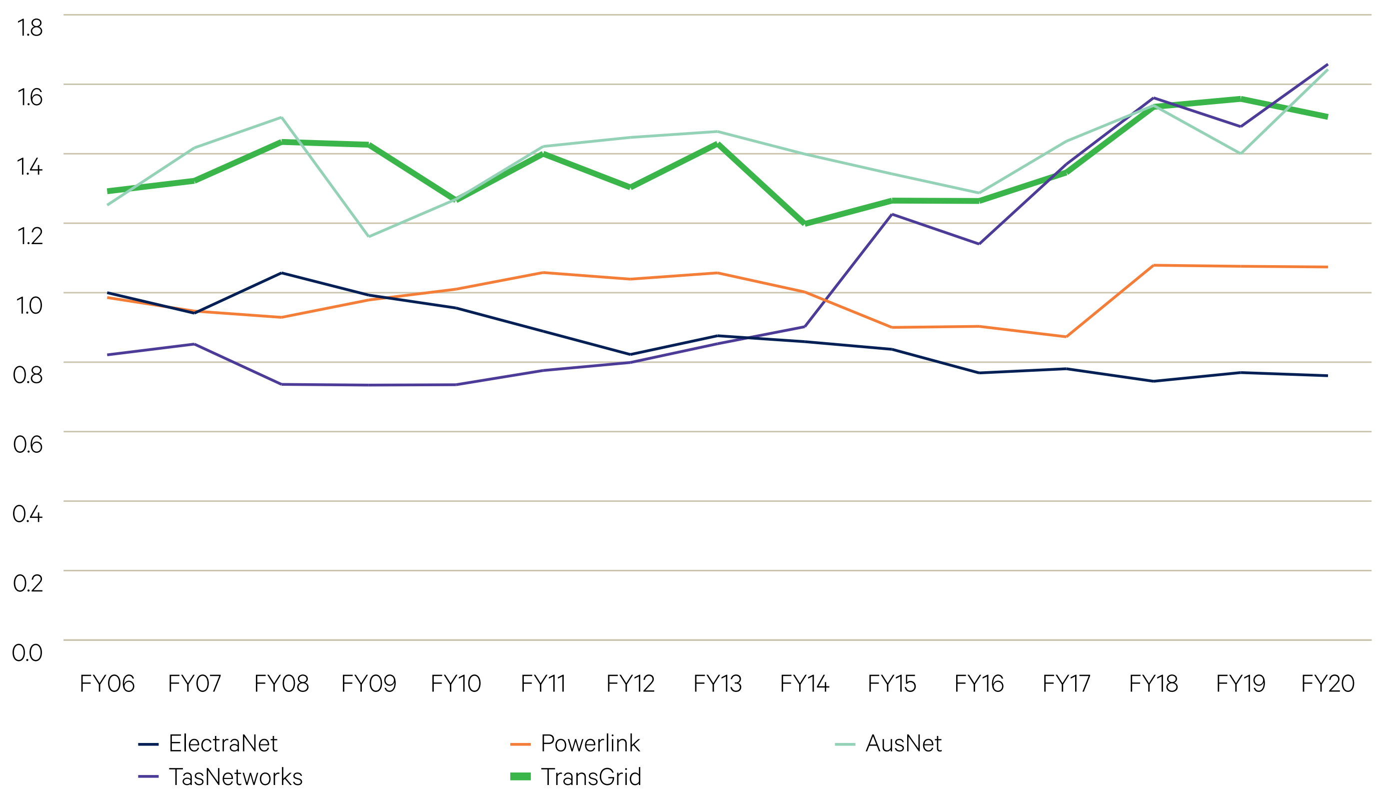
Our opex is efficient

Our opex benchmarks strongly against our peers, as shown in Figure 7.2:

- we are efficient in both absolute and trend terms, with our productivity performance ranking in the middle in comparison with our peers, and progressively improving
- our improved productivity demonstrates that we are responding to the efficiency incentives under the regulatory framework, and
- our current opex has improved relative to our opex incurred in 2016-17, which the AER determined was efficient.

Importantly, TasNetwork's improvements in productivity for its transmission business are unlikely to be reflective of an increase in the productivity for an efficient stand-alone transmission network. This is because TasNetwork's improvements reflect the outcomes of a merger between Aurora, a distribution network, and Transend, a transmission network, to deliver 'synergies and efficiencies'.

Figure 7.2: Opex multilateral partial factor productivity (MPFP) 2005-06 to 2019-20



Source: Economic Insights TNSP MTFP Tables and Charts, August 2021

Base-Step-Trend forecasts

The following table breaks down our base-step-trend forecast for 2023-28.

1 Base year

Our estimated 2021-22 opex is **$197.8 million**.

We estimate our 2021-22 opex will be $34.1 million below the AER's opex allowance, excluding debt raising costs, reflecting the operational efficiencies we have achieved.

2 One-off base year adjustments

We propose to:

- **deduct $5.0 million** in movements in provisions
- **deduct $22.2 million** for non-recurring bush-fire remediation
- **deduct $1.5 million** network support costs
- **add $23.5 million** of ICT costs that were previously capitalised but due to recent changes to IFRIS[35] are now required to be expensed.

Our proposed adjusted base year opex is $192.6 million.

These adjustments are consistent with the AER's preferred approach and its recent transmission determination

3 Rate of change

Rate of change = output growth + real price growth – productivity growth

Output change:

- Energy throughput **0.1% increase** per annum
- Maximum demand **0.0% change** per annum
- Customer numbers **1.3% growth** per annum
- network circuit length **1.5% growth** in 2024

Labour real price increases:[1]

- **0.9%** per annum

Productivity growth:

- **0.3%** per annum

The rate of change increases our overall opex forecast by $50.8 million in the 2023-28 period.

We have applied the AER's rate of change formula to capture the year-on-year change in efficient expenditure due to forecast changes in output levels, prices and productivity.

We have included a positive productivity growth improvement which reduces our overall opex by around $9.7 million in the 2023-28 period.

Notes:

1 Based on forecasts from BIS Oxford Economics

35 IFRIC, Configuration or Customisation Costs in a Cloud Computing Arrangement (IAS 38 Intangible Assets), April 2021. This confirms that configuration or customisation costs in a cloud computing arrangement must be expensed. Subsequently ASIC required Australian corporates to adopt this change for June 2021 reporting. The nature of the changes are explained in KPMGs Cloud computing arrangements costs – updated, Reporting update 24 May 2021, 21 RU-005.

4 Step changes

Step changes are externally driven costs that we will incur that are not in our base year opex and are too material for us to absorb.

- Insurance premiums **$31.7 million**
- Cyber and critical infrastructure security **$24.6 million**
- ISP preparatory activity **$2.9 million**

Our insurance premiums are forecast to increase in the next regulatory period. Since 2018, the global insurance market has experienced significant volatility, with ongoing premium increases and a contraction in available insurance cover capacity. This is placing upward pressure on premiums.

We will incur additional expenditure to meet new cyber security obligations under the Australian Government's proposed Critical Infrastructure 2020 Bill, which is expected to be passed by early 2022.

We will incur additional expenditure to undertake preparatory activities[36] for future ISP projects as determined by AEMO in its ISPs, which it issues every two years. We are required to undertake these activities in accordance with the Actionable ISP Rules.

5 Category specific forecasts

We will incur certain category specific costs.

- Debt raising costs **$23.7 million**
- Network support costs **$0 million**

We engaged an independent expert Frontier Economics to estimate the rate of benchmark debt raising costs for the 2023-28 regulatory period consistent with the AER's accepted estimation methodology.

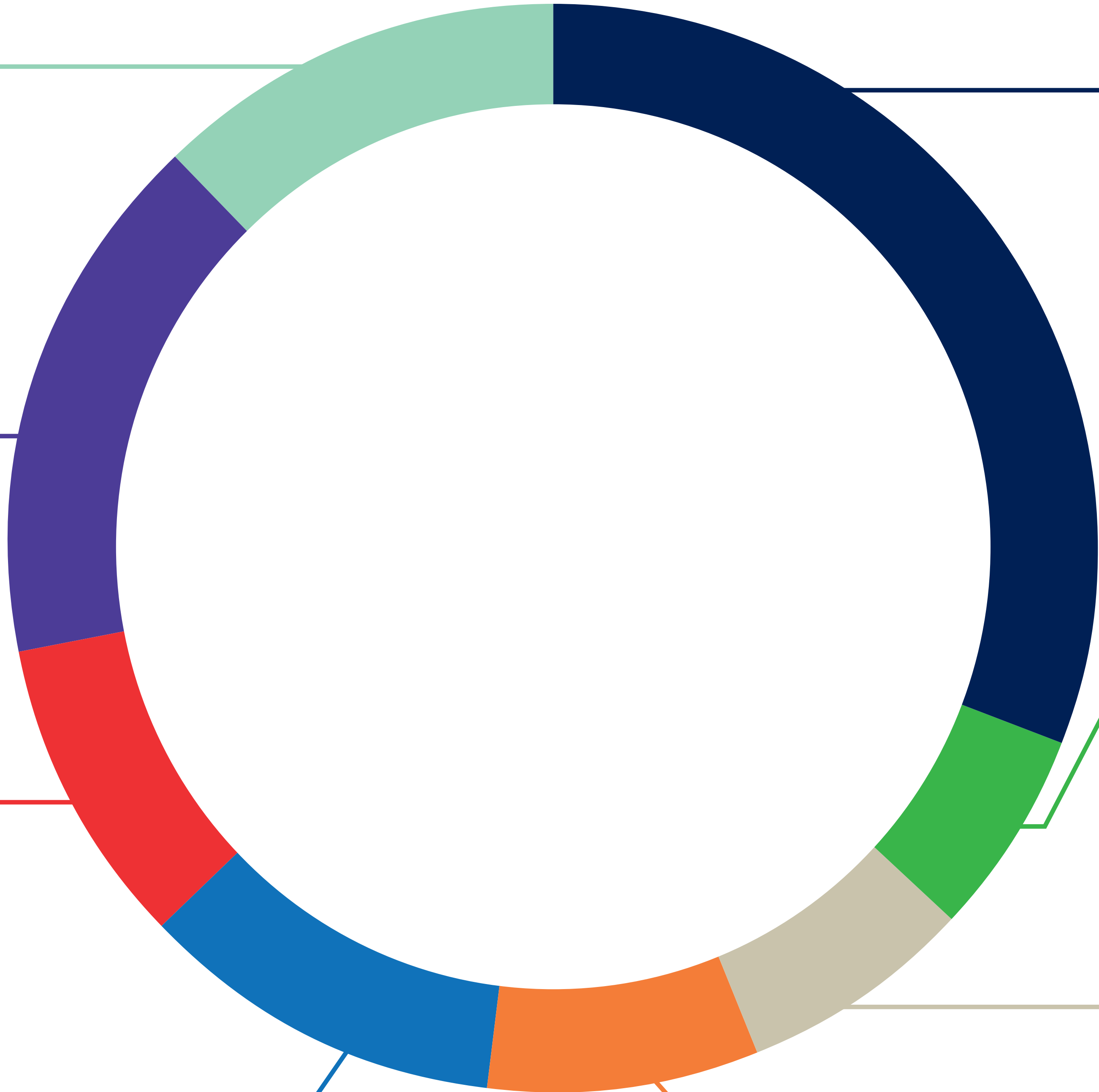
We have not included any cost in our preliminary opex forecast because at this stage we currently do not have any network support contracts in place for the 2023-28 regulatory period.

36 NER rule 5.10.2.

Nature and drivers of our forecast opex requirements

Our opex program is needed for the efficient ongoing operation and maintenance of our assets in an increasingly complex operating environment.

Figure 7.3 provides a breakdown of our 2023-28 opex forecast by category:



$25.4m

Corporate support

- Corporate support functions including finance, regulatory, legal and HR

$34.3m

Customer relations & corporate governance

- Engagement activities with customers and stakeholders and governance functions. This includes community engagement, community partnerships, customer and industry engagement and commitments such as the Energy Charter.

$19.1m

Safety, environment & property management

- Operational costs for maintaining safety and compliance of our property and facilities
- Developing, implementing and maintaining health, safety and environmental strategies, plans and procedures

$24.9m

Information technology

- Operations and Maintenance for corporate ICT systems including software license fees and cloud-based services

$67.4m

Asset maintenance

- Asset maintenance tasks and activities, including inspections, testing, routine/condition based maintenance, and vegetation management based on maintenance strategies and plans

$13.1m

Asset management & network planning

- Activities that support the strategic development and ongoing management of the network including developing, implementing and reviewing asset strategies in accordance with our ISO 55001 asset management system and Electricity Network Safety Management System
- Planning future development of the network, fulfilling our role as jurisdictional planner for NSW and ACT

$16.3m

Network operations and support

- Real-time control-room functions, monitoring of real-time asset performance, condition and fault diagnosis
- Network support, including demand management

$16.8m

Insurances, rates & taxes

- Insurance premiums, property rates (council & water) and taxes incl. land tax

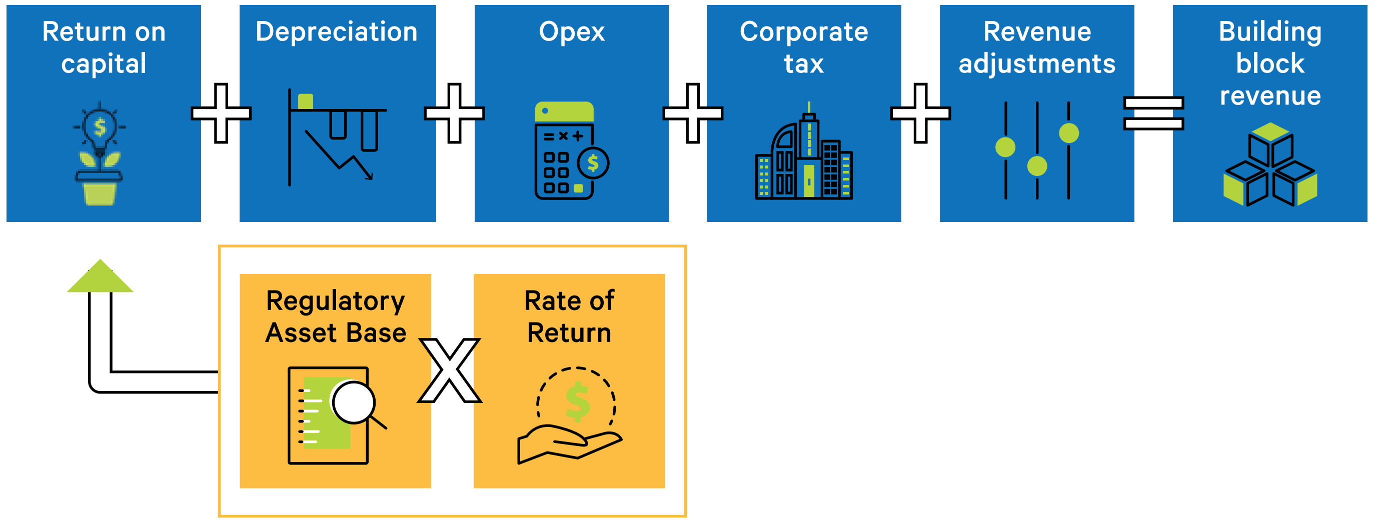
8. Preliminary forecast revenue and indicative bill impacts

We expect our revenue to decrease by **3.2 per cent** or **$128.3 million** compared to the 2018-23 period. We also expect the transmission component, which comprises 7 to 8 per cent of indicative residential household and small business bills, to reduce over the course of the next period by **$16.90**, and **$61.20** per annum respectively.

Forecast revenue and indicative bill impacts

We have used the AER's building blocks to calculate our forecast revenue for the 2023-28 period. The building block components are set out in Figure 8.1.

Figure 8.1: Building blocks revenue components



We expect our 2023-28 forecast (smoothed) revenue to decrease by 3.2 per cent or $128.3 million compared to the 2018-23 period. This is equivalent to a reduction in building blocks revenue (unsmoothed) of $125.5 million, or 3.1 per cent.

Figure 8.2: 2023-28 forecast smoothed revenue

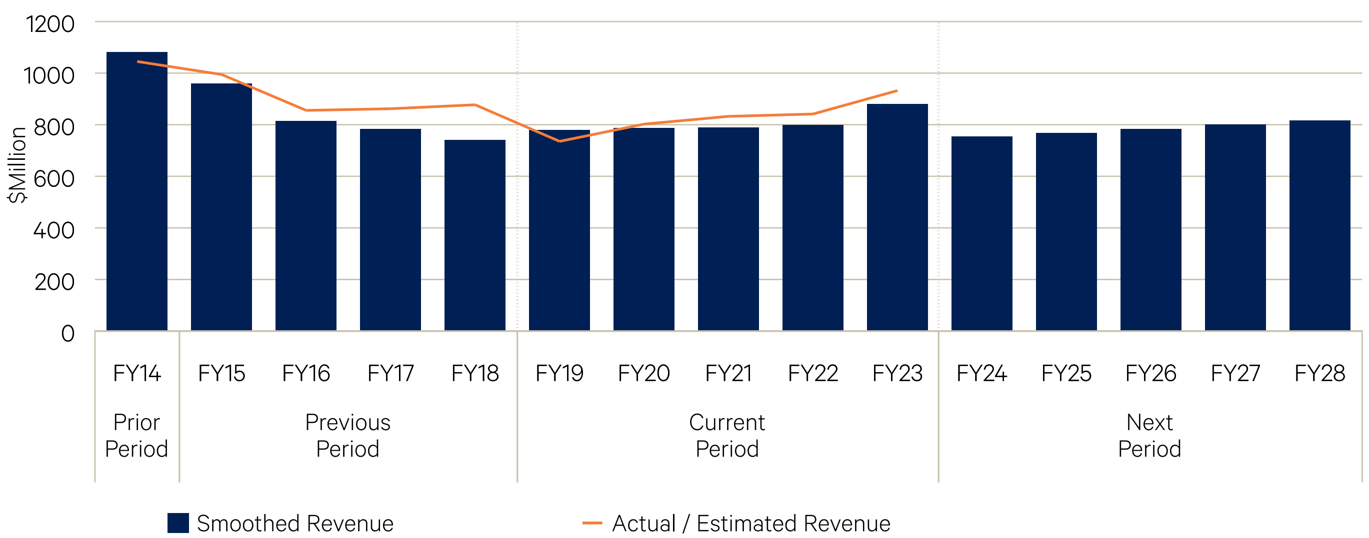
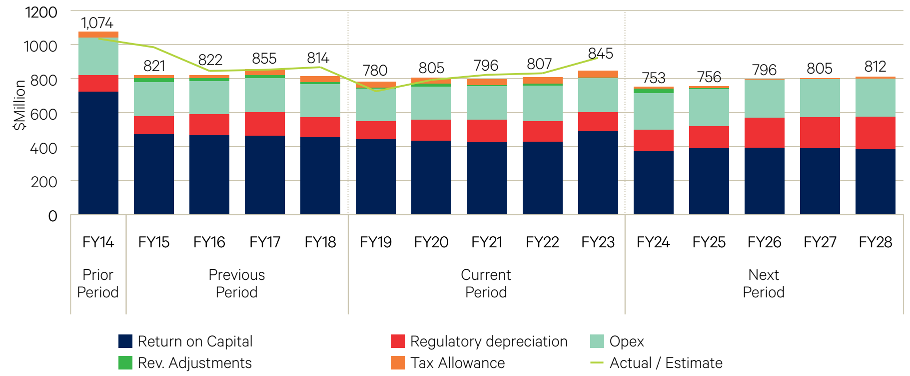


Figure 8.3 shows our forecast revenue by building block component in the 2023-28 period. The key drivers of our revenue reduction are:

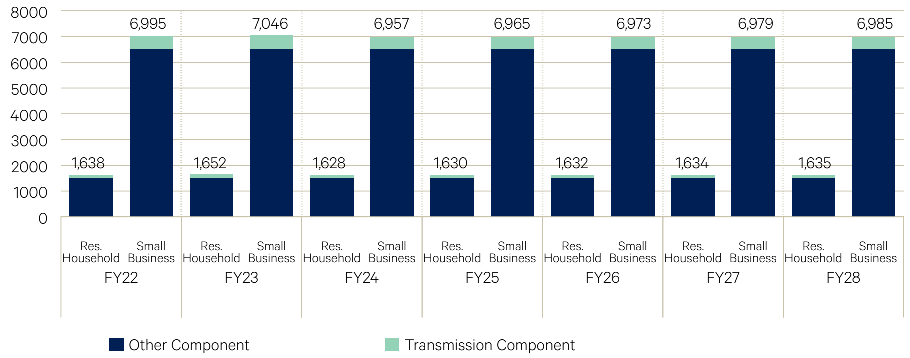
- a lower return on capital, driven by a lower rate of return
- lower projected corporate income tax[37], and
- lower revenue adjustments.

Figure 8.3: Forecast building block revenue by component



We expect that over the course of the next period the transmission component of a typical residential household bill will reduce by $16.90 p.a. and small business bill will reduce by $61.20 p.a. [38].

Figure 8.4: Indicative residential household and small business bills ($)



Notes:

1 The indicative bill uses average bill information published by the AER and the AEMC and assumes that the non-transmission components of the bill stay constant in real dollars.

Figure 8.5: Component of the total retail

7% The cost of our prescribed transmission services represents around 7% of the total typical residential household bill and 8% of total small business bill in NSW and ACT

Electricity supply chain	Proportion of total residential household bill %	Proportion of total small business bill %
Generation	28	24
Transmission	**7**	**8**
Distribution	22	28
Retail and other	15	12
Environmental policies	28	29

Source:

AcilAllen, TransGrid TUOS as a proportion of residential and small business electricity bills, 14 September 2021

37 AER, Final Report Review of regulatory tax approach, December 2018. This approach is reflected in the AER's PTRM and is consistent with NER clause 6A.6.4.

38 We converted our proposed MAR into indicative household bills using the approach used by the AER in its decision on our Project EnergyConnect contingent project application. This converted forecast revenue into indicative household bills using forecast energy throughput and typical household bill information, such as the typical bill size and the share of NSW and ACT residential bills attributed to transmission charges.

Return on capital

Rate of return

The rate of return, or weighted average cost of capital (WACC), represents the cost of funding investments through borrowings from debt markets and investments from equity holders.

We have applied the AER's binding 2018 Rate of Return Instrument (RORI) and recent observable market data to estimate the rate of return for the 2018-23 period. This results in an estimated rate of return of 4.40% for the first year of the 2023–28 regulatory period, based on:

- a return on equity of 4.80%; and
- a return on debt of 4.13%. The return on debt is updated in each year of the regulatory period based on the trailing average approach.

Rate of Return

2018-23: 6.2% p.a.

2023-28: 4.4% p.a.

1.8% p.a.

Figure 8.6: Rate of return calculation

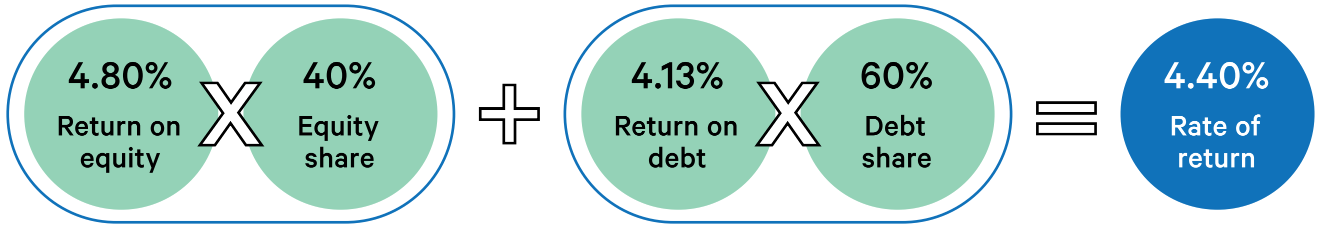


Table 8.1 shows that the reduction in the rate of return in the 2023-28 period is predominately due to lower return on equity parameters and observed bond yields compared to the 2018-23 period.

Table 8.1: 2023-28 rate of return compared to 2018-23

Component	2018-23	2023-28	Basis for 2023-28
Risk free rate	~2.85%	1.14%[1]	Prevailing yields on Commonwealth Government bonds
Market Risk Premium	6.50%	6.10%	2018 RORI
Equity beta	0.70	0.60	
Return on Equity	7.40%	4.80%	
Return on Debt	4.96%–5.97%	4.13%[2]	Trailing average cost of debt based on current market rates
Gearing Ratio	60%	60%	2018 RORI
Nominal Vanilla WACC	**5.94%–6.54%**	**4.40%**	**Reflects parameters above**
Gamma	0.4	0.585	Reflects 2018 RORI

Notes:

1 Calculated based on 20 trading days to 31 August 2021.
2. Based on RBA corporate bond spreads in June and July 2021.

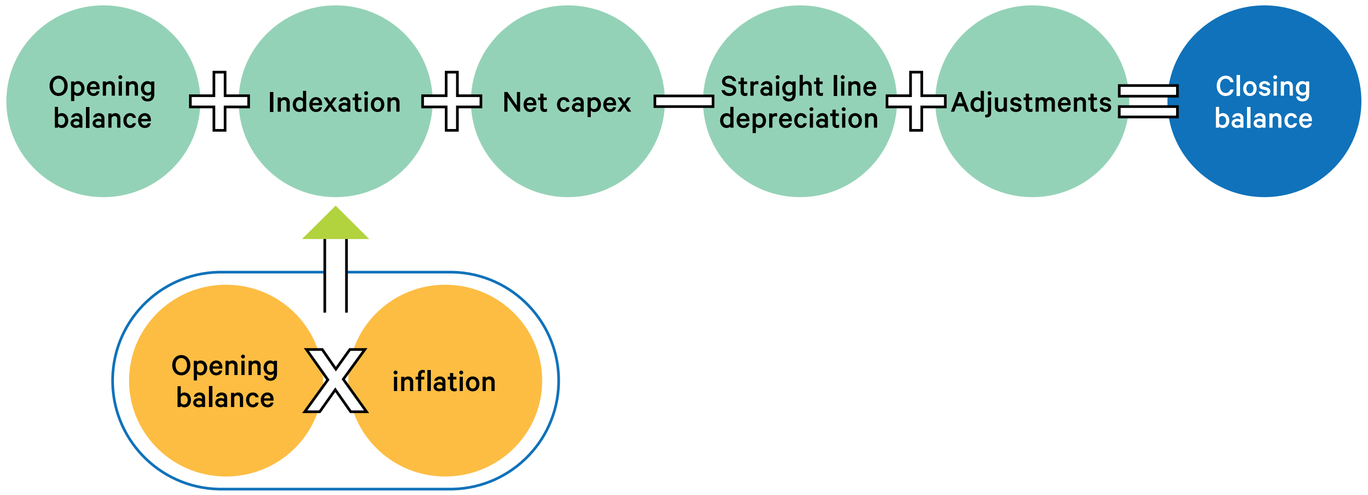
The final rate of return that will apply in the 2023-28 period will be calculated using the 2022 RORI. The AER is currently consulting on the development of the 2022 RORI and expects to publish it in December 2022. The AER will reflect its 2022 RORI decision in its Final Determination for our 2023-28 Revenue Proposal.

Regulatory Asset Base (RAB)

Our RAB is the value of assets used to deliver prescribed transmission services. The RAB measures the unrecovered value of capital investments that we have made, or forecast to make, to provide these services, both now and in the future. The RAB is used to calculate both the return on capital and depreciation building blocks.

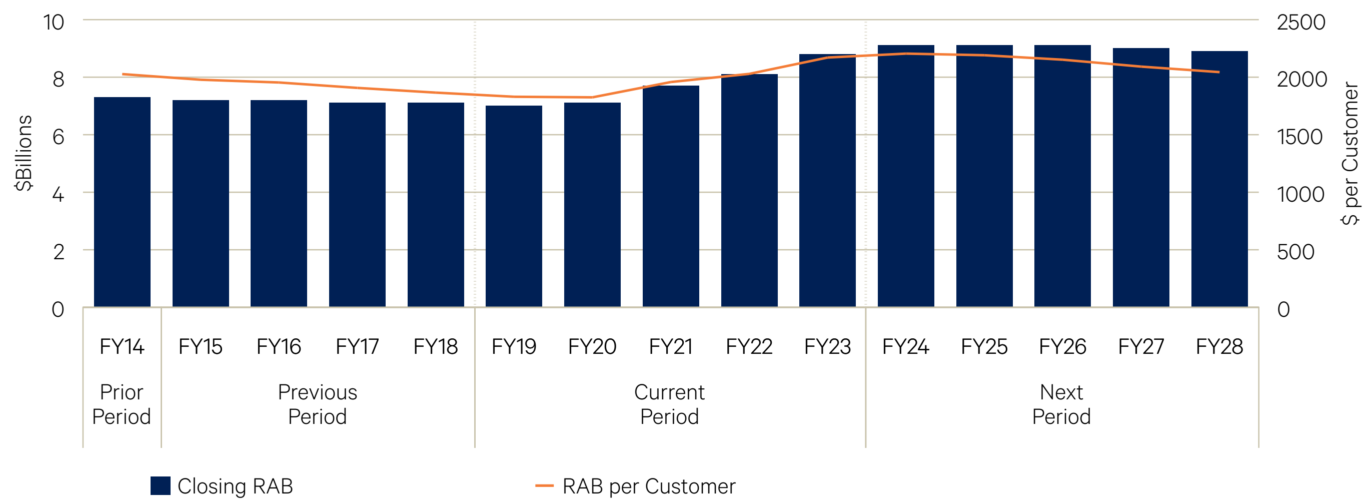
We have rolled-forward the RAB over the 2018–23 and 2023–28 periods using methods consistent with the NER and the AER models.[39]

Figure 8.7: How the RAB changes over time



We expect a slight increase in our regulatory asset base (RAB) over the 2023–28 period after adjusting for new capex and depreciation. Our RAB will increase by $202 million from $8,654 million in 2023-24 to $8,856 million in 2027-28. We forecast a $127.2 million decrease in the RAB value per customer over the 2023–28 period, as our customer numbers are projected to increase by more than our RAB over that period.

Figure 8.8: Our RAB roll-forward including approved ISP projects[40]



39 The AER's roll-forward model (RFM) was used to roll-forward the RAB over the 2018–23 period and the AER's post-tax revenue model (PTRM) was used to roll-forward the RAB over the 2023–28 period.
40 Approved ISP projects are VNI Minor, QNI Minor and Project EnergyConnect.

Depreciation (return of capital)

Depreciation enables us to recover our capital investment over the expected economic life of the assets. Depreciation is deducted from the RAB each year as it is recovered through the regulatory depreciation allowance.

We have forecast our regulatory depreciation allowance using the AER's PTRM. We propose to:

- continue to apply forecast real straight-line depreciation net of indexation of the RAB
- retain the same asset classes and continue to apply the same standard asset lives approved by the AER in its 2018-23 Determination, and
- use the year-on-year tracking approach to calculate depreciation because it is more precise. This is consistent with the approach approved by the AER in its recent decisions for other network businesses.

We propose to use forecast depreciation to roll-forward the RAB in our subsequent regulatory period, from 1 July 2028 – this reflects the AER's preference in its Framework and Approach paper.

Opex

Our preliminary opex forecast is discussed in section 7.

Tax allowance

We pay corporate income tax, like other businesses. Our revenues include a notional corporate income tax allowance for a benchmark firm (net of the value of imputation credits), which reflects our forecast income tax liabilities over the 2023–28 regulatory period.

We have calculated our income tax allowance using the AER's current approach to determining the tax allowance, which was updated in 2018.[41] This reflects the corporate tax rate of 30 per cent (30 cents in the dollar) less the forecast benefit of imputation credits (gamma) of 58.5 per cent, based on the 2018 RORI.[42]

Forecast inflation

Forecast inflation is used in the AER's PTRM to calculate the depreciation building block and to convert real dollar values to nominal dollar values. We have applied a forecast inflation of 2.20 per cent per annum calculated based on the AER's December 2020 final decision on the treatment of expected inflation,[43] which is also reflected in the AER's PTRM.

This method involves:

- a five year estimation window to match the length of the regulatory period, and
- the application of a symmetrical linear glide-path from the Reserve Bank of Australia's (RBA's) short-term forecast of inflation for year 2 to the mid-point of the inflation target band (2.5 per cent) in year 5.

We will update our forecast of inflation later this year when the RBA releases its updated statement on Monetary Policy so that our Revenue Proposal reflects the latest available information.

Revenue adjustments

Incentives schemes

The regulatory framework includes incentive schemes that encourage us to maintain and improve service levels, capex and opex efficiencies and demand management. We propose that the AER's incentive schemes apply in the 2023-28 regulatory period, including the:

- Service Target Performance Incentive Scheme (STPIS)
- Efficiency Benefit Sharing Scheme (EBSS)
- Capital Expenditure Sharing Scheme (CESS), and
- Demand Management Innovation Allowance Mechanism (DMIAM).

We note the AER intends to review the current version of its STPIS, EBSS and CESS given concerns that we and other TNSPs have raised.[44] In particular, we are concerned that the Market Impact Component of the STPIS has become impracticable with the transformation underway in the energy system.

We look forward to participating in the AER's review of these schemes and understand that the updated versions will be published in the second half of 2022. These will be reflected in the AER's Final Decision on our 2023-28 Revenue Proposal.

Shared assets

Our annual revenue requirement must be reduced when annual unregulated revenues from the use of shared assets (i.e. those assets that are used to earn regulated and unregulated revenues) are expected to be greater than 1 per cent of the total smoothed annual revenue requirement for that regulatory year.

We have assessed our expected shared asset revenue for the 2023-28 regulatory period. We expect to reach the materiality threshold. We have therefore reduced our revenue accordingly for the 2023-28 period.

41 AER, Final Report Review of regulatory tax approach, December 2018. This approach is reflected in the AER's PTRM and is consistent with NER clause 6A.6.4.
42 The 2018 RoRI includes a value of imputation credits, or gamma, of 58.5%. This may be updated in the 2022 RORI that the AER is currently consulting on.
43 AER, Final position – regulatory treatment of inflation, December 2020.
44 TransGrid, Request for Revised Framework and Approach Paper, 30 October 2020.

Cost pass throughs

Our operating environment is unpredictable and events beyond our control can substantially change our expenditure within a regulatory period. We exclude some high-cost low probability events from our expenditure forecasts to ensure that customers only pay for them if and when they actually occur.

The NER include cost pass through provisions so that we can recover (or pass through) costs of defined, unpredictable, high cost events that are not included in the expenditure and revenue forecasts in the AER's Final Decision. The AER determines the efficient costs of these events through the pass-through application process if and when they occur during the period.

In addition to the prescribed pass through events in the NER, we propose that the nominated pass through events that apply in the 2018-23 period continue in the 2023-28 period, including:

- insurance coverage event
- insurer's credit risk default event
- natural disaster, and
- terrorism event.

The AER has accepted these four pass through events in its recent decisions for other network businesses.

Contingent projects

Contingent projects are required when the need, timing and cost of projects are uncertain when a revenue proposal is submitted to the AER. Treating projects in this way ensures that customers only pay for them if and when they proceed.

We have two categories of contingent projects:

- standard contingent projects, and
- NSW Renewable Energy Zones (REZ).

In addition, as requested by stakeholders, we have listed below future or Actionable ISP projects for transparency, although these are automatic contingent projects under the Actionable ISP Rules, and therefore do not require AER approval.

Standard contingent projects

Given the rapidly changing energy market, we have identified 15 contingent projects, with an indicative total cost of $3,993 million. The key drivers of these projects are:

- system inertia and strength requirements
- expected demand growth, and
- expected new generation connection.

These projects are listed in Table 8 2.

Table 8.2: Standard contingent projects

Standard contingent project	Total indicative cost ($M)	Basis for proposed trigger
1 Meeting NSW system inertia requirement	259	AEMO declares inertia shortfall
2 Meeting NSW system strength requirement	632	AEMO declares system strength shortfall[1]
3 Strategic Easement acquisition for supply to Sydney from the south	278	AEMO's ISP and land value growth
4 Supply to Bathurst Orange and Parkes - stage 1	107	RIT-T is complete
5 Supply to Bathurst, Orange and Parkes - stage 2	466	Demand growth
6 Increase supply from northern NSW	414	New generation connection
7 Improve capacity of Southern NSW lines for renewables	388	New generation connection
8 Improving stability of the South-Western NSW network	173	New generation connection
9 Increase capacity for generation in Wollar to Wellington Area	104	New generation connection
10 Increase capacity for generation in the Beryl area	76	New generation connection
11 Supply to ACT network capability	93	Demand growth
12 Supply to Inner Sydney Area	544	Demand growth and asset decommissioning
13 Transmission Line 86 Replacement	264	RIT-T is complete
14 Moree Special Activation Precinct	41	Demand growth
15 Supply to North West Slopes Area	155	RIT-T is complete
Total	3,993	

Notes:

1 To be reviewed following AEMC's final decision on the Efficient management of system strength on the power system rule change proposal.

Renewable Energy Zones (REZ)

The NSW Government has declared five REZ projects as part of its Energy Roadmap, which we propose to treat at this stage as contingent projects. This is because the NSW regulatory framework[45] has not yet been finalised and the cost recovery mechanism for these projects remains unclear. These projects will not be treated as contingent projects if in the future they are:

- subject to cost recovery through the NSW regulatory framework, or
- classified as actionable ISP projects by AEMO in its ISPs. In this case, these projects would be progressed in accordance with the NER automatic contingent project provisions for Actionable ISP projects.

Table 8.3 lists REZ projects declared by the NSW Government. The North Western NSW REZ is not included because it does not have any capex forecast for the 2023-28 period.

Table 8.3: NSW REZ projects

Proposed contingent project	Total indicative cost estimate ($M)	Proposed trigger
New England REZ	2,398	New generation of more than 1,100 MW is reasonably anticipated in the New England area of northern NSW (near Armidale and Tamworth)
South Western NSW REZ	1,466	New generation of more than 1,000 MW is reasonably anticipated in South Western NSW
Central West Orana REZ	673	New generation of more than 900 MW is reasonably anticipated to connect in central western NSW (west of Wollar and Mount Piper)
Hunter region REZ	259	New generation of more than 1,000 MW is reasonably anticipated in the Hunter region of NSW
Illawarra region REZ	259	New generation of more than 1,000 MW is reasonably anticipated in the Hunter region of NSW
Total	**5,054**	

Future or actionable ISP projects

We have not included future or Actionable ISP projects as contingent projects because they are, or are expected to be, subject to the automatic contingent project provisions for Actionable ISP projects under the Actionable ISP Rules. The automatic contingent project provisions require written confirmation from AEMO that:

- the project addresses the need and aligns with the optimal development path in the most recent ISP, and
- the cost of the preferred option does not change the status of the project as part of the optimal development path.

AEMO's 2020 ISP identifies the following future and Actionable ISP projects to be delivered in the 2023-28 regulatory period. We will update this list based on AEMO's draft 2022 ISP, which it will publish in December 2021.

Table 8.4: Actionable and future ISP projects based on AEMO's 2020 ISP

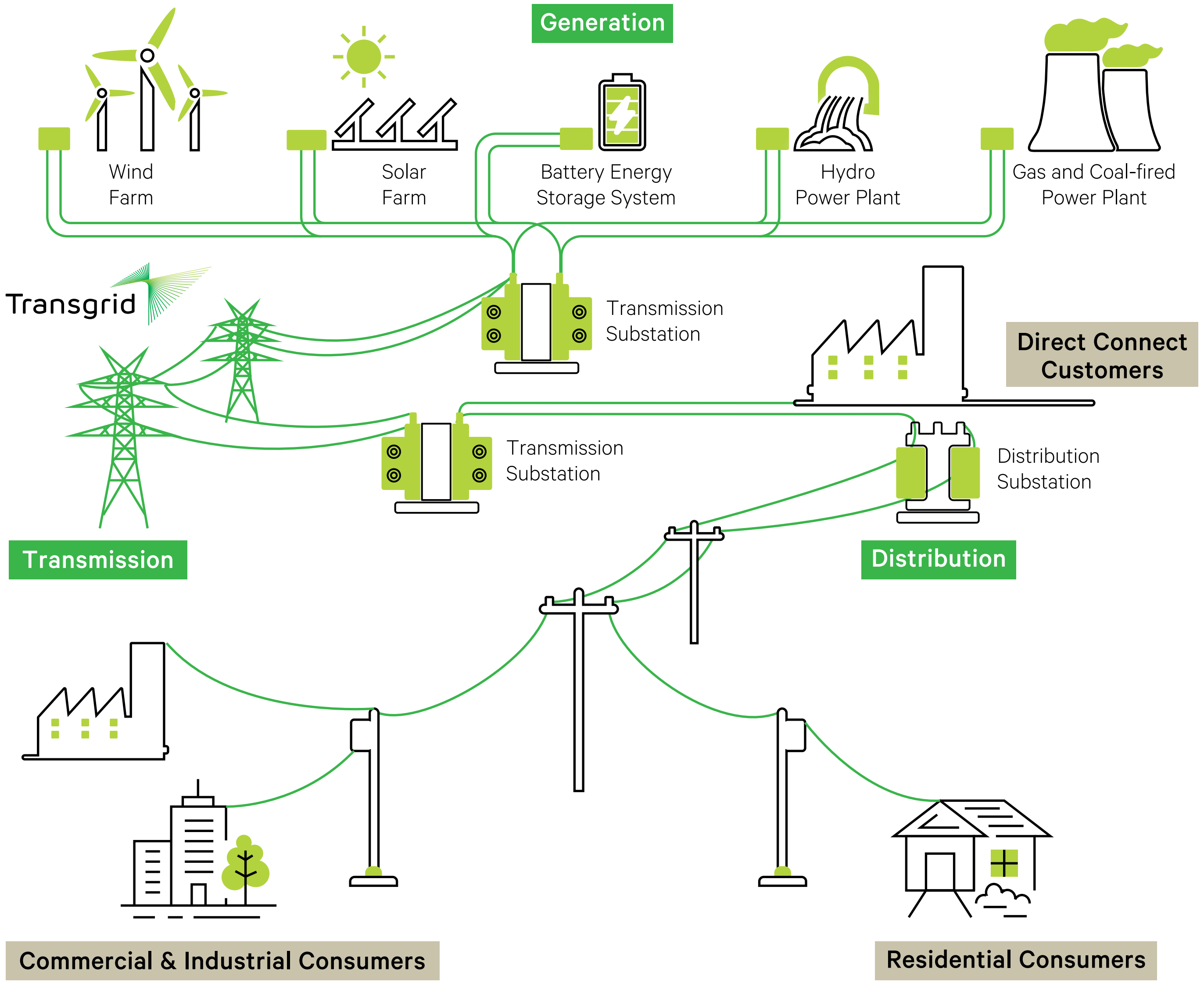
ISP projects	2023-28 indicative cost ($M)	Total indicative cost ($M)
Actionable ISP projects		
HumeLink	1,117	3,434
VNI West	1,672[1]	4,220
Future ISP projects		
QNI (Medium / Large)	157[2]	4,219
Supply to Sydney from the North	911	911
Supply to Sydney from the South	2,336	2,336
Total	**6,192**	**15,120**

Notes:

1 Includes NSW and VIC components.
2 Includes NSW and QLD components.

45 The NSW Electricity Infrastructure Investment Act 2020 (EII Act) establishes a NSW-specific cost recovery route for transmission investments associated with the Electricity Infrastructure Roadmap.

Supply chain



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