



Jemena Electricity Networks (Vic) Ltd

2021-26 Electricity Distribution Price Review Regulatory Proposal

Attachment 05-01

Forecast capital expenditure



Table of contents

Glossary	iv
Abbreviations	v
Overview	vii
1. Our customers' future needs and expectations	1
1.1 Introduction	1
1.2 Customer priorities	2
1.3 Customer and demand forecasts	3
1.4 Objectives of our capital expenditure forecast	7
1.5 References	8
2. Our asset management system	10
2.1 Asset management system summary	12
2.2 Asset management system governance	13
2.3 References	14
3. Capital planning governance and forecasting	15
3.1 Capital project prioritisation	15
3.2 Our Project Management Methodology	16
3.3 Capital expenditure forecasting	16
3.4 Business case assessments	18
3.5 Risk management	19
3.6 Procurement	19
3.7 Capital works delivery	19
3.8 References	20
4. Replacement expenditure	21
4.1 Summary	21
4.2 Our approach to asset replacement planning	25
4.3 Poles	30
4.4 Pole top structures	34
4.5 Overhead conductors	39
4.6 Underground cables	41
4.7 Service lines	43
4.8 Transformers	47
4.9 Switchgear	51
4.10 SCADA, network control & protection systems	54
4.11 Other	59
5. Connections expenditure	65
5.1 Summary	65
5.2 General connections	67
5.3 Major customer connection projects	71
5.4 References	72
6. Augmentation expenditure	73
6.1 Summary	73
6.2 Demand-driven augmentation	76
6.3 Non-demand driven augmentation	87
6.4 References	97
7. Non-network expenditure	98

7.1	Summary.....	98
7.2	IT & communications.....	99
7.3	Motor vehicles.....	112
7.4	Buildings and property.....	116
7.5	Other.....	118

List of appendices

Appendix A Feedback on our draft plan
Appendix B Compliance with National Electricity Rules
Appendix C Capital contributions
Appendix D Asset management system governance
Appendix E Capital planning governance and forecasting

Glossary

Current regulatory period	The regulatory period commencing 1 January 2016 and concluding 31 December 2020
Economic life	The age of an asset at which the total cost of providing the required level of service from the asset no longer represents the lowest long-run cost to customers of providing that required service (i.e. after considering alternatives)
ES Regulations	<i>Electricity Safety (Bushfire Mitigation) Regulations 2013</i> (Vic) (including subsequent amendments made in 2016 and 2017)
Gross capital expenditure	Total capital expenditure, inclusive of amounts which are customer funded through capital contributions
Hosting capacity	The capacity of the network to accommodate bi-directional power flows due to exports from distributed energy resources
Net capital expenditure	Total capital expenditure, less capital contributions and disposals
Next regulatory period	The regulatory period commencing 1 July 2021 and concluding 30 June 2026
Probability of exceedance	The likelihood that a given level of maximum demand forecast will be met (or exceeded) in any given year. A forecast of 10 POE maximum demand is the level of annual demand that is expected to be exceeded one year in ten.
Reset RIN	The Regulatory Information Notice served by the AER on 4 October 2019 to allow the AER to make a distribution determination for the period 1 July 2021 to 30 June 2026
RIN Response	Our response to the information sought by the AER in the Regulatory Information Notice served on 4 October 2019
Technical life	The typical expected life of an asset before it fails in service under normal operating conditions. The technical life may differ between networks (due to different operating environment factors) and between asset classes.

Abbreviations

ABC	Aerial Bundled Cable
ACIF	Australian Construction Industry Forum
ACR	Automatic Circuit Recloser
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AESCSF	Australian Energy Sector Cyber Security Framework
AMI	Advanced Metering Infrastructure
AS	Australian Standards
BTS	Brunswick Terminal Station
CBRM	Condition Based Risk Management
CESS	Capital Expenditure Sharing Scheme
CN	Coburg North zone substation
COO	Coolaroo zone substation
CS	Coburg South zone substation
CY	Calendar Year
DER	Distributed Energy Resources
DMS	Distribution Management System
ECA	Energy Consumers Australia
EP	East Preston zone substation
ERP	Enterprise Resource Planning
ESMS	Electricity Safety Management Scheme
EWP	Elevated Work Platform
FE	Footscray East zone substation
FW	Footscray West zone substation
FY	Financial Year
GVM	Gross Vehicle Mass
HBRA	Hazardous Bushfire Risk Area
HV	High Voltage
ICCS	Incremental Cost Customer Specific
ICSN	Incremental Cost Shared Network
ICT	Information and Communications Technology
IR	Incremental Revenue
IT	Information Technology
JEN	Jemena Electricity Networks (Vic) Ltd

JGN	Jemena Gas Network
KLO	Kalkallo zone substation
LGA	Local Government Area
LV	Low Voltage
MCR	Marginal Cost of Reinforcement
NEO	National Electricity Objective
NEL	National Electricity Law
NER	National Electricity Rules
NS	North Essendon Zone Substation
OMS	Outage Management System
P	Preston zone substation
PMM	Project Management Methodology
POE	Probability of Exceedance
PPI	Partial Performance Indicator
PTRM	Post Tax Revenue Model
PV	Photovoltaic
REFCL	Rapid Earth Fault Current Limiter
RIN	Regulatory Information Notice
RTS	Real Time Systems
SCADA	Supervisory Control and Data Acquisition
SCS	Standard Control Services
SP	Security Profile
VCR	Value of Customer Reliability

Overview

About this document

This document explains our forecast capital expenditure for standard control services (**SCS**) for Jemena Electricity Networks (Vic) Ltd (**JEN**) over the 2021-26 regulatory period (**next regulatory period**). This includes the amounts we are proposing to spend, how we developed our forecast and how this expenditure meets our customers' future needs and expectations and the requirements of the National Electricity Rules (**NER**).

This document is structured as follows:

- the remainder of this overview section provides a summary of the:
 - views, preferences and other inputs from customers we have used to develop our capital expenditure forecast
 - customer outcomes we are seeking to achieve
 - expenditure drivers impacting our capital expenditure forecast
 - objectives for our capital expenditure
 - amount and categories of our capital expenditure forecast
 - major projects and initiatives we plan to deliver for customers through our forecast
 - specific areas of our capital expenditure forecast which have been shaped by customer feedback
 - ways in which our proposal represents the most efficient means of delivering our objectives and customer outcomes
- section 1 summarises our customers' future requirements for our network, including our customers' expectations and preferences and our demand forecasts
- section 2 describes our asset management system
- section 3 describes our capital planning, governance and forecasting approaches
- the remaining sections then present our forecasts for the AER's four categories of direct capital expenditure:
 - section 4 details our replacement expenditure forecast
 - section 5 details our connections expenditure forecast
 - section 6 details our augmentation expenditure forecast
 - section 7 details our non-network expenditure forecast.

Appendix A details the stakeholder feedback we received in response to our January 2019 draft plan, and Appendix B deals with a number of NER compliance matters.¹ Appendices C to E provide further detail on material presented in the body of this document.

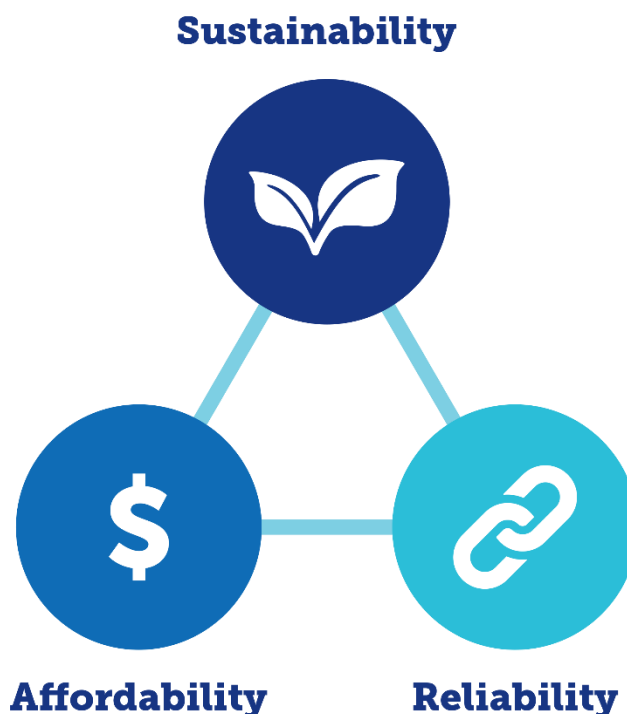
An explanation of our capital expenditure during the 2016-20 regulatory period (**current regulatory period**) is provided as Attachment 05-02.

Unless otherwise stated, dollar figures throughout this document are expressed in real June 2021 dollars, exclusive of overheads, on a gross basis (inclusive of capital contributions).

¹ Including demonstrating how our forecast capital expenditure reflects the capital expenditure objectives, criteria and factors outlined in NER cl 6.5.7.

Customer input

We set out to design our regulatory proposal around delivering the kind of network our customers have told us they want. Broadly, customers across different segments outlined key common priorities during our engagement with them, which were aligned to the energy trilemma of affordability, reliability and sustainability.



Viewed through the energy trilemma, customers told us that they expect:

- **Affordability** – energy prices remain a key concern for many of our customers, and they require JEN to spend efficiently and look for ways of improving affordability over time
- **Sustainability** – many customers are expecting to install distributed energy resources (**DER**) in the future, with environmental benefits a key driver, and they want JEN to play a role in enabling these new technologies and products
- **Reliability** – customers expect JEN to keep the electricity network as reliable as it is today.

Expenditure drivers influencing our proposal

Our capital expenditure forecast (in conjunction with our operating expenditure forecast) is the most prudent and efficient way for us to deliver these customer outcomes in the context of a range of **expenditure drivers** during our next regulatory period:

- **Demand from residential and small business customers in our network continues to grow**
 - we expect 30,000 new residential dwellings will be constructed during the next regulatory period within our network area (annual growth of approximately 1.5 per cent), which covers some of the fastest growing local government areas in Victoria—including Melbourne’s greenfield urban growth corridors and several brownfield development areas, such as Preston and Fairfield
 - we expect 1,300 new businesses to open in our network area

- **The way customers use our services is changing**
 - we expect over 65 MW of new renewable generation and 50 MWh of new battery storage capacity will seek connections to our network, with the take-up of DER being driven by government policies designed to meet ambitious Victorian renewable energy targets
 - customers' interest in using the grid to trade clean energy generated by distributed energy resources will continue to grow
- **We need to support major infrastructure projects and new commercial customers**
 - construction of the North East Link tunnels
 - new Western General Hospital in Footscray
 - increasing supply needs of major commercial customers with large loads, such as data centres
 - major urban infill developments in Alphington (YarraBend) and Moonee Ponds (Mooney Valley Racecourse)
 - significant asset relocation works required for a number of infrastructure projects, including level crossing removals and the construction of the Melbourne Airport rail link
- **We need to replace assets as they reach the end of their lives or no longer perform as required**
 - some network assets reaching the end of their technical lives and whose condition indicates they are at heightened risk of failure will need to be replaced
 - we need to continue replacing assets, particularly pole-top structures, in bushfire-prone areas
 - we need to continue replacing families of overhead services to phase out those which pose a safety risk to customers
 - we need to respond to growing cybersecurity threats to our IT systems
- **We need to comply with significant new regulatory obligations**
 - Victorian bushfire safety regulations require us to install new bushfire mitigation technology in some areas by 2023
 - the move to five-minute settlement and global settlement in the National Electricity Market requires us to make a number of significant IT system changes.

Our capital expenditure forecast: delivering for customers

To reflect our customers' desired outcomes and our key expenditure drivers, we have developed four **objectives for our capital expenditure forecast**. These objectives reflect various regulatory obligations—including the National Electricity Objective (**NEO**) set out in the *National Electricity Law (NEL)* and the capital expenditure objectives and capital expenditure criteria set out in clause 6.5.7 of the *National Electricity Rules (NER)*—as well as incorporating specific customer feedback we received through our engagement processes. These are shown below alongside our four capital expenditure categories—replacement, connections, augmentation and non-network.

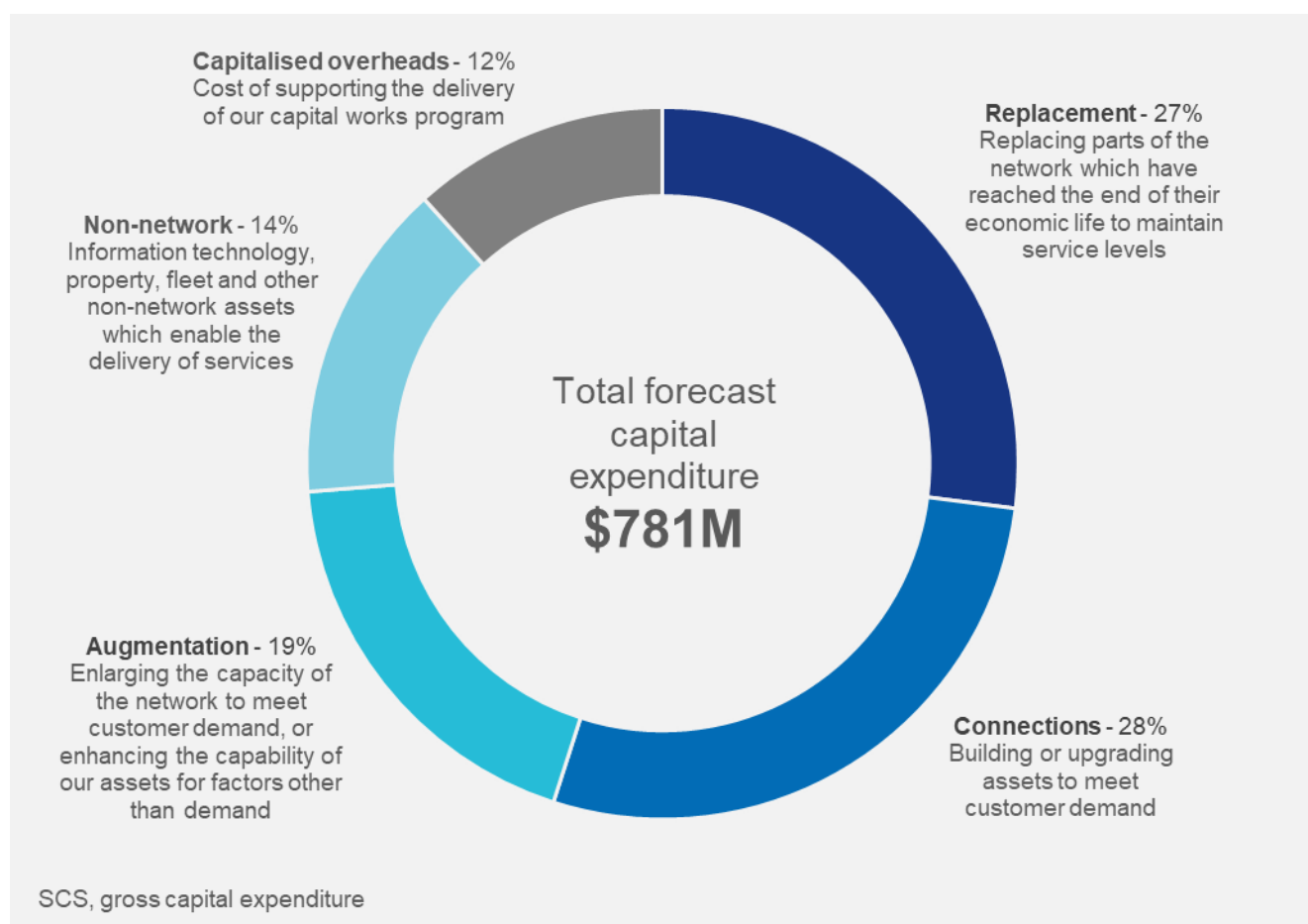
	 Replacement	 Connections	 Augmentation	 Non-network
Meet customers' expectations that we should maintain our current levels of network reliability (including the frequency and duration of network outages) at the most efficient cost over the long term				
Manage safety, environmental, physical security and cybersecurity risks to as low as practicable and comply with all applicable regulatory obligations at the most efficient cost over the long term				
Connect new customers to the electricity network and meet the changing energy needs of existing customers, ensuring we can meet or manage expected demand for all customers at the least cost over the long-term				
Efficiently minimise any constraints on grid exports from distributed energy resources to the extent possible				

In line with our customers' priorities and our objectives for capital expenditure, we've developed a forecast which will allow us to deliver the following **customer outcomes** efficiently:

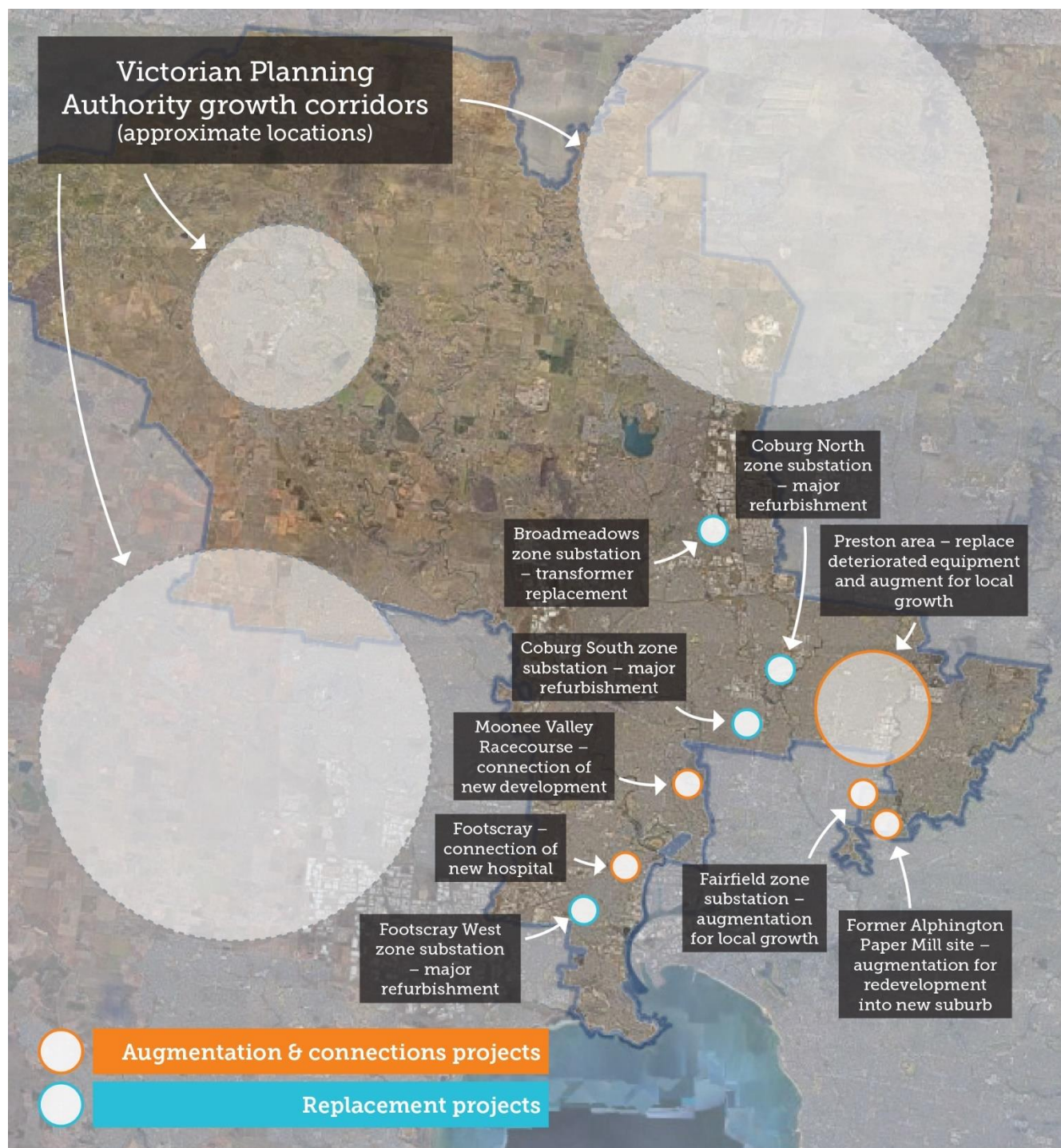
- maintain the safety of our customers, staff and the general public
- maintain our current levels of network reliability over the long-term
- improve efficiency and affordability of our services over the long-term
- increase customers' ability to export excess energy from their DER to the grid, and for our network to accommodate localised energy trading in the future
- provide more choices for customers in how they interact with and receive information from us.

What are we proposing to spend?

Our forecast capital expenditure for SCS for the next regulatory period is \$781M (inclusive of overheads). We forecast our capital expenditure using the AER's preferred categories – these categories and their respective portions of our forecast capital expenditure are shown on the chart below. Throughout this document, the expenditure categories and sub-categories displayed align with those defined in the Reset Regulatory Information Notice (**Reset RIN**) issued by the Australian Energy Regulator (**AER**) to JEN on 4 October 2019.



Our forecast expenditure includes several large electricity network projects around greater north-west Melbourne, as well as works we're doing to support other major infrastructure and urban development projects in our network area. Key projects are shown on the map below.



Our capital expenditure by category—historical and forecast—is set out in the chart and table below. Our forecast capital expenditure is in line with our estimated spend during the current regulatory period. This is despite our forecast containing significant expenditure required to meet Victorian bushfire mitigation obligations during the first half of the next regulatory period—after which, our forecast capital expenditure declines. On a per customer basis, our forecast expenditure is 8.7 per cent lower than what we will spend in the current regulatory period.²

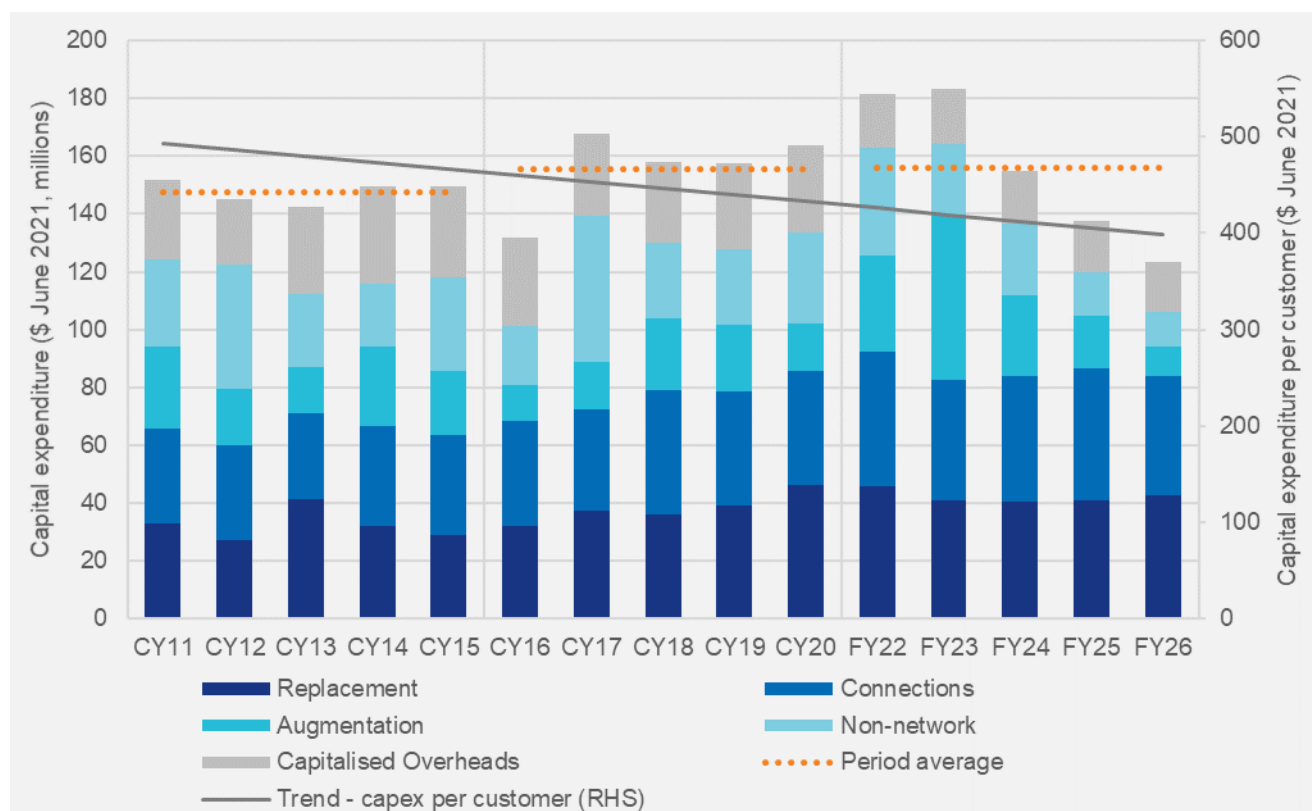


Table OV–1: SCS capital expenditure by category, 2021-26 period (\$ June 2021, millions)^{3,4}

Capital expenditure category	FY22	FY23	FY24	FY25	FY26	Total
Replacement	45.9	41.0	40.3	41.1	42.6	210.9
Connections	33.4	57.1	27.7	18.2	10.1	146.5
Augmentation	46.3	41.4	43.8	45.2	41.3	218.0
Non-network	37.3	24.5	24.9	15.2	12.0	113.9
Capitalised overheads	18.7	19.3	18.1	17.8	17.4	91.2
Gross capital expenditure	181.6	183.4	154.7	137.5	123.4	780.5
Capital contributions	32.9	29.6	30.6	30.5	29.4	153.0
Asset disposals	0.2	0.1	0.1	0.1	0.1	0.5
Net capital expenditure	148.5	153.7	124.1	106.9	93.9	627.1

² Part of this reduction is due a change in our capitalisation approach requiring us to expense all corporate overheads from 1 January 2021. This will lower the growth in our asset base and reduce pressure on the prices paid by our customers in the long-term.

³ Consistent with the requirements of NER cl 6.5.7(b)(3) and S6.1.1(1).

⁴ Equity raising costs are not shown in this table. Equity raising costs are transaction costs that we incur when we raise equity. JEN recognises equity raising costs as capital expenditure within the Post Tax Revenue Model (PTRM) and amortises these costs over the life of the assets that they are used to fund. The AER has applied a benchmark approach in its recent regulatory decisions for determining costs for raising equity through dividend reinvestment plans and seasoned equity offerings. These costs have been forecast using the AER's approach contained in the PTRM included in this regulatory proposal.

How have we responded to customer feedback in our forecast?

Our customers spoke, and we listened. Customers' views and feedback are integral to our future planning, and ensuring that we are best placed to deliver expenditure which is in our customers' long-term interests. The table below summarises key views from customers that have shaped our capital expenditure forecast.

Customer feedback	How our capital expenditure forecast responds to this feedback
Customers expect JEN to ensure its network continues to operate at current levels of reliability	<p>Our forecast represents an efficient level of capital expenditure required to continue to plan, operate and maintain our network at the current levels of reliability—such as outage frequency and outage duration—for customers. This includes ensuring that the reliability we provide does not degrade over time, reflecting strong sentiment from customers on this issue.</p> <p>Our forecast does not include additional capital expenditure to improve network reliability, as our customers have largely told us that they do not see the value in paying for these improvements.</p> <p>However, we will continue to make our investment decisions with the knowledge that our customers place a high value on reliability, meaning we need to continuously seek smarter and more innovative ways for delivering an improved customer experience while balancing this with customers' concerns about energy affordability.</p> <p>Our forecast expenditure includes:</p> <ul style="list-style-type: none"> • routine and non-routine replacement expenditure (section 4) • augmentation expenditure (section 6) • non-network IT (recurrent and non-recurrent maintain, sections 7.2.2 and 7.2.3, respectively).
<p>Customers expect us to:</p> <ul style="list-style-type: none"> • provide safe and affordable services, including passing on any savings • run an efficient, future-proof network. 	<p>Our forecasts reflect the prudent and efficient costs of meeting customers' expectations and regulatory obligations over the long-term. We have adopted a range of measures outlined in the section below to ensure that our capital expenditure forecast is as efficient as possible.</p> <p>Additionally, our forecast includes a number of activities (proposed under our Future Grid program) which will provide us with new technology allowing us to optimise future decisions about how we design and build the network that meets our customers' changing needs, putting downward pressure on our network replacement and augmentation expenditure—and therefore our prices—over the long-term. This expenditure is contained in the augmentation and non-network IT categories of our forecast, refer to section 6.3.1.1 for further information.</p>
Customers want our network to accommodate growing demand, including increased exports from DER into the grid.	<p>Recognising that our customers do not consider constraints on energy exports from DER to be acceptable, our capital expenditure forecast includes a suite of activities under our Future Grid program. We assessed a range of options and found our proposed initiatives represented the most efficient means of enabling greater DER exports in the future, compared to augmenting the network by continually adding more distribution substations or limiting exports. In the future, providing greater access to the grid for DER is likely to unlock opportunities for our customers such as trading excess renewable energy in their local area.</p> <p>Our Future Grid program forms part of the augmentation and non-network IT categories of our forecast, refer to section 6.3.1.1 for further information.</p>

Customer feedback	How our capital expenditure forecast responds to this feedback
<p>Customers expect us to improve channels of customer service, including access to usage and service status information.</p>	<p>Our forecast includes capital expenditure on IT systems to enable us to improve the availability and accessibility of information for our customers, mainly residential and small-medium business customers. This includes better integrating our systems to provide more options for customers in choosing how they interact with us and more personalised information for customers. Our plans to provide more transparent information and faster resolution of queries include providing live updates around planned outages, more detailed information about unplanned outages and consistency in customer information used in interactions with customer service representatives.</p> <p>This expenditure forms part of our non-network IT category in our forecast, refer to section 7.2.3 for further information.</p>



Why is our forecast the most efficient way of delivering the outcomes our customers expect?

Given the importance our customers place on efficiency and energy affordability, we have a strong record of being consistently ranked as among the most efficient distribution businesses in Australia for our capital expenditure in the AER's Annual Benchmarking Reports.⁵ Consistent with this, and in compliance with the *capital expenditure criteria*,⁶ our capital expenditure forecast represents the efficient costs that a prudent operator would incur to achieve the *capital expenditure objectives*,⁷ including a realistic expectation of the demand forecast and required cost inputs. We have ensured this by:

- employing our best-practice expenditure planning and governance processes, including our ISO 55001-accredited Asset Management System, to ensure that optimal planning and investment decisions are made which minimise the total lifecycle cost of achieving our expenditure objectives and providing services to customers
- engaging an external expert to develop maximum demand and customer number forecasts, and continuing to use a risk-based, probabilistic planning approach to our augmentation and replacement expenditure
- applying Condition Based Risk Management modelling to ensure our replacement activity volumes are based on the best available information about the actual condition and health of our assets, allowing us only to replace (or remediate) assets when necessary to maintain service levels, avoiding unnecessary early replacements
- using efficient unit rates—which have been influenced by the strong incentives of the Capital Expenditure Sharing Scheme (**CESS**) during the current regulatory period—to develop key parts of our capital expenditure forecast, in addition to obtaining independent bottom-up cost verifications of several major non-routine projects we propose to undertake
- exploring the potential for capital-operating expenditure trade-offs and non-network alternatives in our augmentation, replacement and non-network expenditure forecasting. Our proposal allows us the flexibility to undertake demand management (operating expenditure) where economic to reduce load at risk due to growing demand or degrading asset condition, and our proposed Future Grid program contains activities which involve the substitution of non-network capital and operating expenditure for network augmentation expenditure
- employing combinations of bottom-up and top-down forecasting methodologies when developing our proposal,⁸ including using top-down methods to validate our bottom-up forecasts, and ensuring delivery and scope efficiencies are reflected in our total forecast expenditure
- considering future levels of customer demand and opportunities to “de-rate” assets in our replacement planning, resulting in us reducing our replacement expenditure forecast compared to undertaking like-for-like replacements
- employing our robust cost estimation methodology and procurement processes to ensure all input costs to our capital expenditure forecast are efficient
- considering interdependencies with other areas of our regulatory proposal, particularly our operating expenditure forecast (which reflects the expenditure required to support ongoing asset maintenance and inspection activities which are necessary in the context of our efficient condition-based asset replacement and augmentation programs).

⁵ Australian Energy Regulator, Annual benchmarking report: Electricity distribution network service providers, November 2019. JEN is ranked fourth of 13 on capital multilateral partial factor productivity, which considers the productivity of distributors' use of key network equipment—overhead lines, underground cables and transformers. JEN's ranking is not impacted by the re-statement of our RIN data.

⁶ NER cl 6.5.7(c)(1).

⁷ NER cl 6.5.7(a).

⁸ Our forecasting approaches for each category of expenditure are explained throughout this document in the respective sections.

1. Our customers' future needs and expectations

1.1 Introduction

Our role is to deliver a safe and reliable electricity supply to our customers. We must therefore plan and build our network in a way which ensures this at the most efficient cost over the long-term.

However, our customers' energy needs and expectations continue to evolve rapidly. Over the last decade, customers have become increasingly empowered to make choices and take control of their energy needs. Changes in electricity prices, technology and government policy have driven unprecedented growth in small-scale renewable energy generation, such as solar photovoltaic (**PV**) systems. This decentralisation and decarbonisation of generation are expected to continue to gather pace over the next decade, as our customers take up new DER technologies such as battery storage and electric vehicles.

The decisions our customers make about how they use energy will have a significant impact on how we plan, design, build and maintain the electricity network both today and in the future. Because the investments we make in our network today can last up to 50 years, understanding the trends driving our customers' behaviour and their future energy requirements is critical to us being able to best deliver the services they expect at the most efficient cost over the long-term.

Megatrends driving electricity sector transformation

We have identified five global megatrends that are likely to drive fundamental changes in the structure and function of the electricity system over the long term.⁹ They are:

- Decentralisation—generation from large centralised conventional power stations is decreasing, and output from smaller DER is increasing
- Digitisation—digital technologies are enabling devices across the electricity network to communicate and share data, providing opportunities for customers and the management of the network itself
- Decarbonisation—Australia has emission reduction targets in line with the Paris Agreement, which over time will increase the amount of variable renewable generation sources connected to the grid
- Electrification—decarbonisation is also likely to mean the electrification of activities which are currently fossil-fuelled, such as transport
- The rise of energy storage—the cost of battery storage is rapidly declining and likely to continue to fall.

Ultimately, it is our customers' behaviour which will determine the extent to which these megatrends impact how we deliver our services. While the exact timing and magnitude of these trends are challenging to estimate, and several different future scenarios could eventuate, our objective over the next regulatory period is to take actions which provide the most efficient foundation for us to respond to a range of different futures. We have reflected the need to provide a flexible foundation which can adapt to these trends in the future in the objectives of our capital expenditure forecast, explained further in section 1.4.

Through our engagement program, our customers have told us that they continue to expect us to continue to provide a safe, low cost and reliable electricity network. However, as our customers change the way they use energy, we must ensure that the network remains best placed to continue efficiently delivering these customer outcomes despite these changes in customer behaviour. For example, our network was historically designed and built to deliver electricity to customers (one-way flows), but as the take-up of DER grows our network will increasingly need to facilitate two-way power flows. Because of this, we must carefully focus on ensuring our network has sufficient **hosting capacity**¹⁰ for DER exports to the grid and minimise the risk of customers being unable to export.

⁹ Refer to section 3.2 of *Jemena Electricity Networks 2021-26 Regulatory Proposal* for further discussion.

¹⁰ Hosting capacity is the capability of the distribution network to receive power exported by our customers from DER.

1.2 Customer priorities

Customer engagement has been central to the development of our capital expenditure forecast. Jemena's values emphasise a vision that prioritises customer value through identifying and understanding customers' needs. To ensure that our forecast capital expenditure for the next regulatory period is in our customers' long-term interests—namely that it enables us to provide the network services they expect at the most efficient cost over the long-term—we must first understand what our customers want and expect.

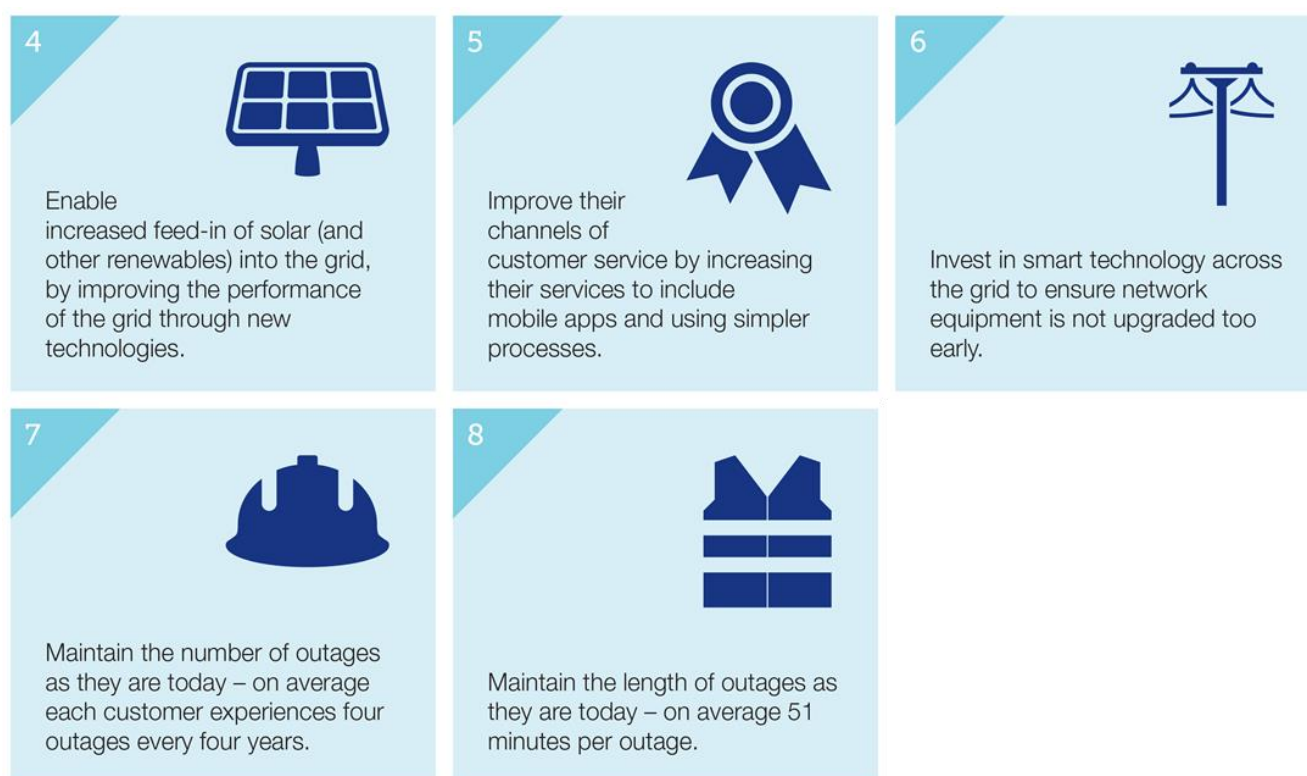
Our customer engagement journey, including the segments of customers we engaged with and our methodologies, is detailed in Attachment 02-01 to our regulatory proposal. This section provides an overview of the key themes and views we heard from our customers as relevant to our capital expenditure. Broadly, customers across several different segments outlined some key common priorities during our engagement with them, including that they expect us to:

- provide affordable services
- maintain the current level of reliability of its network services
- run an efficient, “future-proof” network
- play a key enabling role for new technologies and products that have emerged with the growth of DER.

Some customer and stakeholder segments also outlined other priorities, including that they want us to:

- pass on any savings to customers to put downward pressure on prices
- ensure its network continues to operate at a high level of reliability and should invest to safeguard the distribution network to ensure the impact of growing DER exports is minimised.

JEN's People's Panel also made several specific recommendations, with recommendations 4 to 8 being directly relevant to our capital expenditure forecast, as shown in Figure 1–1. We accepted these recommendations and made a commitment to the Panel that these would shape our regulatory proposal.

Figure 1–1: People's Panel recommendations relevant to our capital expenditure forecast

As part of our engagement on this regulatory proposal, we published a draft plan for consultation in January 2019 and undertook a deep dive session with several stakeholders. We received specific feedback in response to our draft plan, with Appendix A listing this feedback and our responses.

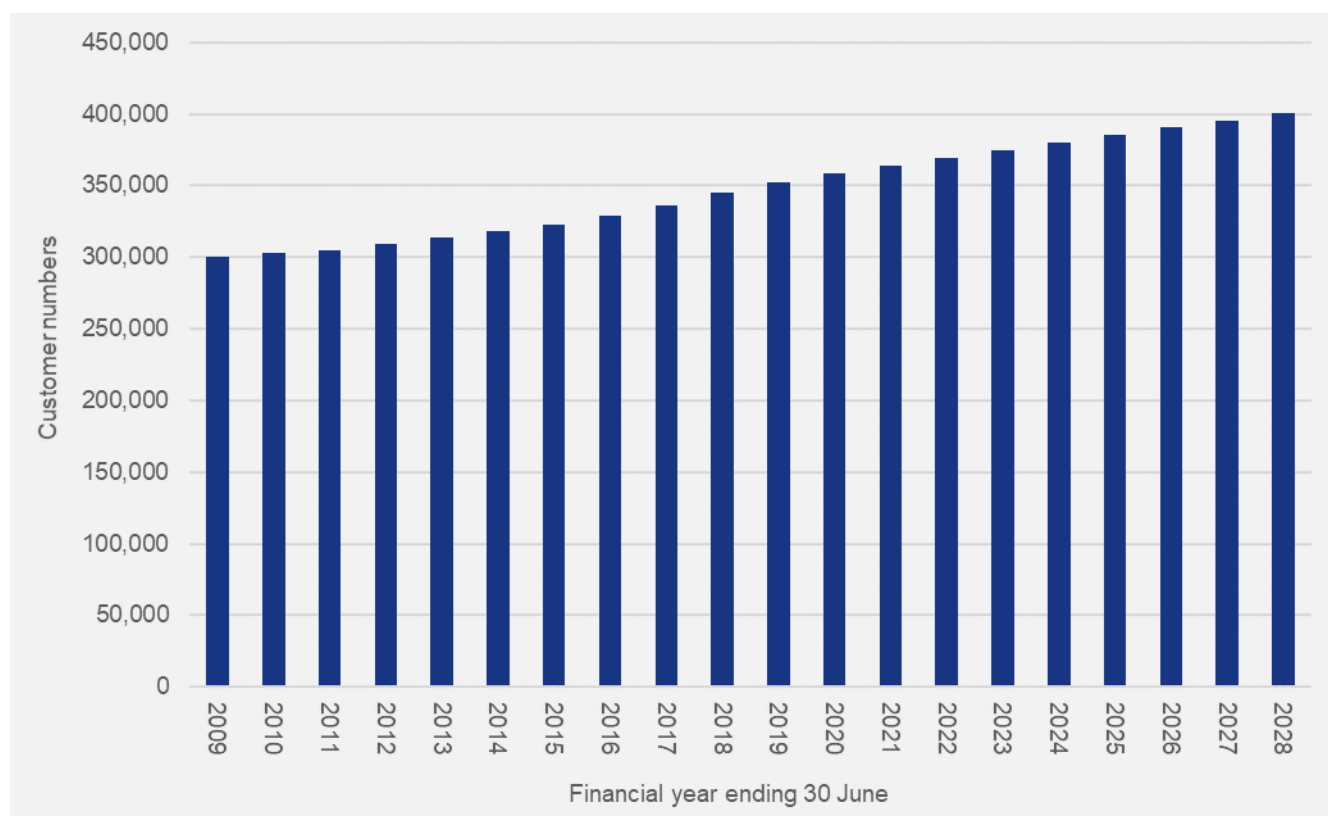
1.3 Customer and demand forecasts

Forecasts of customer numbers, electricity consumption and maximum electricity demand provide a quantified view of our customers' behaviour over the medium term (10-year time horizon). These factors are a crucial input to our forecast of the capital expenditure—particularly in relation to connections and augmentation capital expenditure.

We engaged independent energy forecasting experts ACIL Allen Consulting to prepare these forecasts at a whole-of-network level.¹¹ To ensure we can understand and plan for the likely impacts of new energy technologies on our network, ACIL Allen Consulting has also prepared forecasts of the uptake of rooftop solar PV, battery storage and electric vehicles.

The number of customers connected to our network is forecast to grow throughout the next regulatory period, underpinned by population and economic growth in the north-west greater Melbourne area, as shown in Figure 1–2.

¹¹ ACIL Allen Consulting's Demand forecast report is provided as Attachment 05-03.

Figure 1–2: JEN historical and forecast total customer numbers

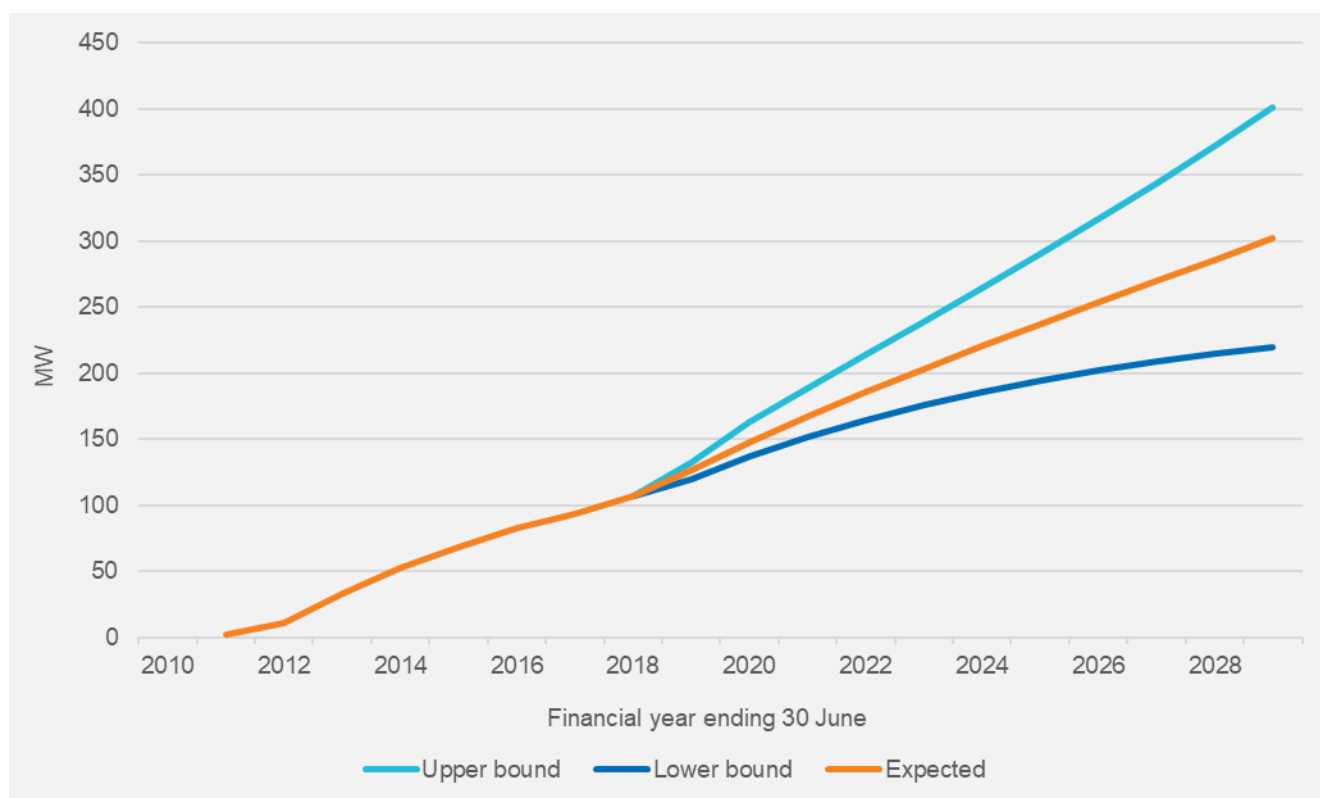
Source: ACIL Allen Consulting, JEN Demand Forecasts 2019-2028 (Attachment 05-03)

Our customers' take-up of new energy technologies, particularly solar PV, is also expected to continue to grow during the next regulatory period. Similarly to other networks in Australia, rooftop solar PV capacity installed within our network increased from almost zero in 2010 to 108 MW by June 2018. ACIL Allen Consulting's forecast of PV take-up within the JEN network over the next decade takes into account expected changes in PV system installation costs, network electricity prices and structures, feed-in tariffs and government policies (including the Victorian Government's Solar Homes scheme).

ACIL Allen's forecast of expected PV take-up for JEN is illustrated in Figure 1–3, which also shows the upper and lower bound estimates.¹² Rooftop solar PV capacity is expected to more than double by June 2026, with an additional 146 MW of rooftop solar PV capacity to be installed. This is equivalent to an annualised growth rate of over 11 per cent per annum to June 2026. However, we expect growth to be higher in the early years (18 per cent between 2018 and 2019) before declining steadily to 7 per cent between 2025 and 2026. We also expect to see strong growth in the take-up of battery storage systems over the next decade, with the total capacity of systems connected to our network forecast to increase from zero in June 2018 to 82 MWh in June 2026.

This growth in new energy technologies, particularly solar PV, increasingly requires us to consider and assess new forms of constraints and other challenges when planning, building and operating our network assets. Just like thermal network constraints caused by growth in maximum demand, we must identify and plan to address emerging hosting capacity constraints, to protect the security of the network and ensure we can maintain current levels of network reliability, consistent with our customers' expectations. Further discussion on the future take-up of DER and its impact on our network's hosting capacity can be found in section 6.3.1.2 and our Future Grid investment proposal (Attachment 05-04).

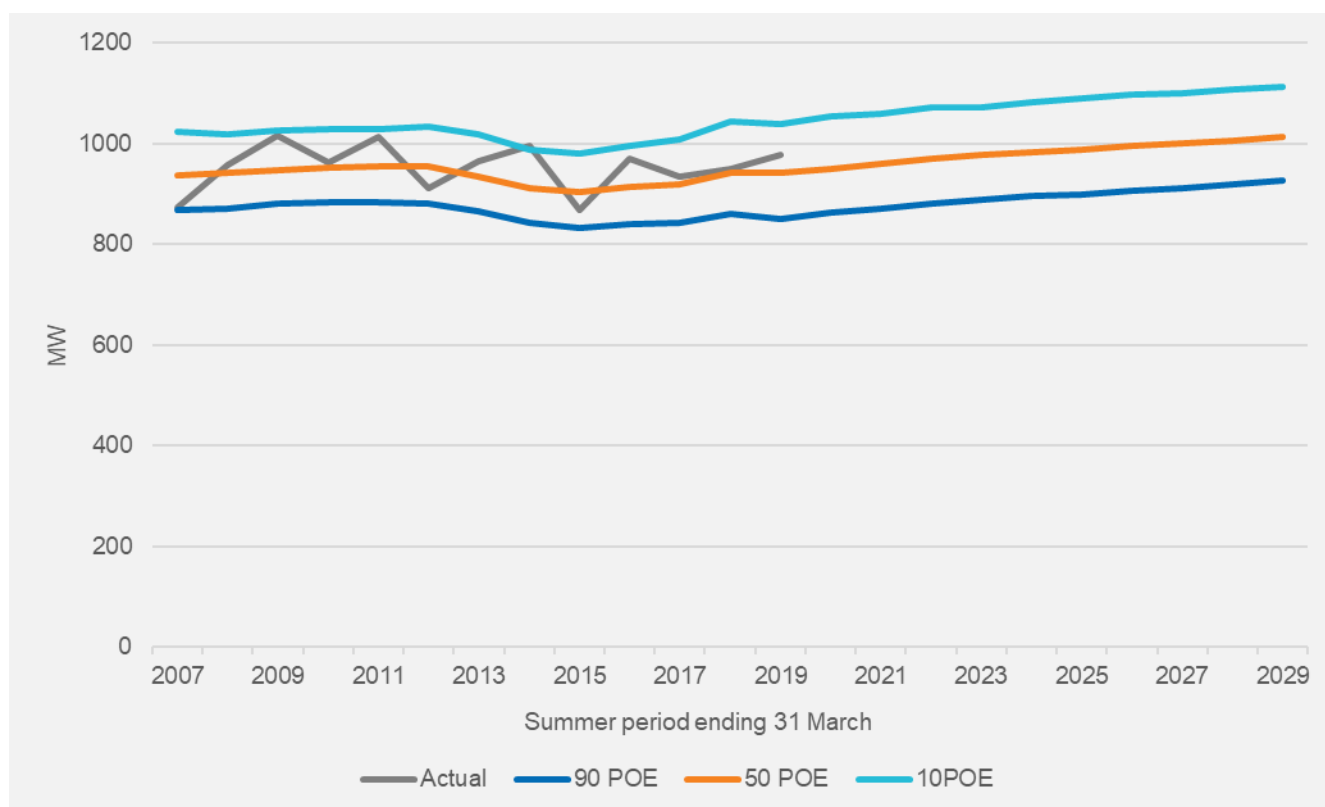
¹² Our network plans and forecast expenditure are based on the 'expected' forecast.

Figure 1–3: Installed rooftop solar PV capacity, historical and forecast

Source: ACIL Allen Consulting, JEN Demand Forecasts 2019-2028 (Attachment 05-03)

ACIL Allen Consulting uses forecast customer numbers and DER take-up and output, combined with other factors such as weather and electricity prices, to produce forecasts of maximum demand at a whole-of-network ('system') level for JEN at different levels of **probability of exceedance (POE)**. ACIL Allen Consulting's 'top-down' system forecast shows maximum summer demand growing at 0.8 per cent per annum (50 POE) between 2019 and 2026¹³ on average across our entire network, as shown in Figure 1–4.

¹³ Years refer to summer periods ending 31 March.

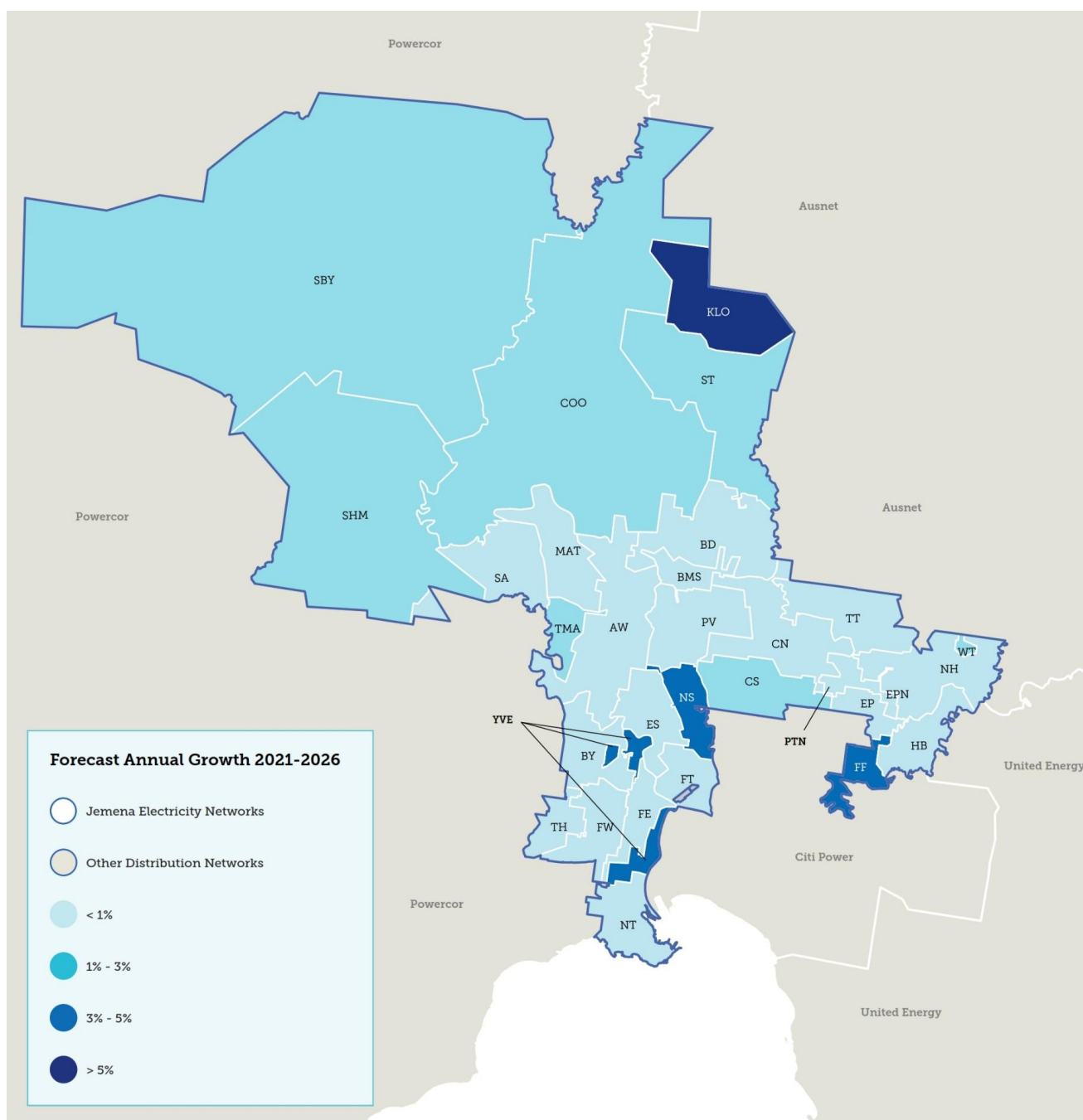
Figure 1–4: Summer system maximum demand (MW)

Source: ACIL Allen Consulting, JEN Demand Forecasts 2019-2028 (Attachment 05-03).

It is important to note that the top-down approach to forecasting maximum demand at a system level can hide spatial diversity in demand, such as at a zone substation or feeder level. In practice, it should be expected that the rate of maximum demand growth at various locations within the network can differ significantly from the *average* rate of growth across the entire network. This is particularly relevant for JEN, given our network covers areas ranging from greenfield urban development corridors where demand is growing strongly, to older industrial areas where demand is declining as customers shut down.

Critically, it is network constraints at these localised levels of our network which drive almost all of our demand-driven augmentation expenditure. We, therefore, prepare bottom-up spatial maximum demand forecasts for each zone substation supply area and reconcile these to the top-down system maximum demand forecast. This spatial diversity in forecast maximum demand growth is illustrated (by zone substation supply area) in Figure 1–5. It shows maximum demand in supply areas such as Kalkallo, Fairfield, Yarraville and North Essendon is forecast to increase at a strong rate, while the rate of growth is slower in areas such as Pascoe Vale, Coburg North and Heidelberg.

Further information about our customer and demand forecasts can be found in section 5 of this document and in ACIL Allen Consulting's demand forecast report (Attachment 05-03).

Figure 1–5: Forecast summer maximum demand growth by zone substation supply area

(1) Growth shown is based on 50 POE maximum demand forecasts.

1.4 Objectives of our capital expenditure forecast

The two sections above provided an overview of our customers' future expectations and needs—in terms of what services they expect us to provide (and their attributes, such as reliability) and how they are likely to use these services and our network in the future. These are fundamental drivers of the investments we must make in our network to ensure we are best placed to meet these expectations efficiently. In developing our capital expenditure forecast, there are some other drivers which we have considered, particularly in light of customers' expectations that we continue to maintain the current level of reliability of our network services. These other expenditure drivers

include the condition of our assets and their expected ability to perform as required in the future, and regulatory obligations we must comply with.

We developed four objectives to guide all capital expenditure within our forecast, which are based on:

- explicit feedback we received from customers through our engagement
- other drivers of our capital expenditure, such as the condition of our assets and regulatory obligations
- the capital expenditure objectives¹⁴ and criteria¹⁵
- the NEO.

These objectives, and the categories of our capital expenditure forecast, which are necessary for us to achieve them, are outlined in Table 1–1. The relevance of each objective to our capital expenditure forecast is also set out in the first section of sections 4 to 7 of this document.

Table 1–1: Objectives for our capital expenditure forecast

Objective	Replacement	Connections	Augmentation	Non-network
Meet customers' expectations that we should maintain our current levels of network reliability (including the frequency and duration of outages) at the most efficient cost over the long term. ¹⁶	●		●	●
Manage safety, environmental, physical security and cybersecurity risks to as low as practicable and comply with all applicable regulatory obligations at the most efficient cost over the long term. ¹⁷	●		●	●
Connect new customers to our network and meet the changing energy needs of existing customers, ensuring we can meet or manage expected demand for all customers at the least cost over the long term. ¹⁸		●	●	
Efficiently minimise any constraints on grid exports from distributed energy resources to the extent possible. ¹⁹			●	●

1.5 References

Supporting documents included as part of our regulatory proposal or response to the Reset RIN in relation to our customers' future needs and expectations are listed below.

Document title	Location
Attachment 02-01 Our customer, stakeholder and community engagement	Regulatory proposal
Attachment 02-02 Capire Community consultation report - 20200131 - Public	Regulatory proposal

¹⁴ NER cl 6.5.7(a).

¹⁵ NER cl 6.5.7(c)(1).

¹⁶ Consistent with NER cl 6.5.7(a)(1) and (3).

¹⁷ Consistent with NER cl 6.5.7(a)(2) and (4).

¹⁸ Consistent with NER cl 6.5.7(a)(1).

¹⁹ Consistent with NER cl 6.5.7(a)(1), (2) and (3).

Document title	Location
Attachment 02-03 Capire Small business consultation report	Regulatory proposal
Attachment 02-04 Capire Reconvening the Jemena people's panel	Regulatory proposal
Attachment 02-05 Capire People's panel price reset timing update	Regulatory proposal
Attachment 02-06 Customer Council's feedback on Jemena's 2021-25 EDPR	Regulatory proposal
Attachment 05-03 ACIL Allen Electricity demand forecasts report	Regulatory proposal
JEN Internal Demand Forecast Report 2019	RIN Response

2. Our asset management system

This section provides an overview of our asset management system.²⁰ Our asset management system is the framework of asset-related policies, processes and procedures we use to ensure that we can achieve our objectives. JEN is committed to employing industry best practice in asset management to prudently manage our assets over their life cycle, to ensure the efficient delivery of services which meet our customers' needs and expectations over the long term.

Network design, construction, maintenance, operations, asset investment and innovation, are vital components of prudent asset management, and will directly impact safety, prices and customer service. We undertake all of these activities in accordance with our asset management system, and it is particularly relevant in the context of our forecast capital expenditure.

Best practice management systems

In a demonstration of our commitment to best practice asset management, our asset management system conforms with and has been certified to international standards ISO 55001 (*Asset Management – Management Systems – Requirements*) and ISO 27001 (*Information technology – Security techniques – Information security management systems*). Jemena was the first utility in Australia to be jointly certified to these standards, achieving this in November 2018.

ISO 55001 provides a framework to help organisations effectively manage their asset portfolio in response to business objectives and stakeholder requirements. ISO 27001 meanwhile provides a framework to help organisations effectively manage corporate information and data assets, both of which are critical to supporting efficient asset management decision making.

The ISO 55001 certification complements JEN's previous certification to PAS 55 (this publicly available specification from the British Standards Institute was a forerunner to ISO 55001 and basis upon which it was developed). Our asset management system provides a robust engineering/technical and financial/economic framework to consider the many variables required for informed decision making. This facilitates decision making that achieves the optimal balance between performance, costs and risks over the long-term. For information security, decision making endeavours to facilitate results that maintain the appropriate level of information confidentiality, integrity and availability. Our decision-making frameworks consider a suite of hierarchical objectives, themselves reflecting our customers' and stakeholders' requirements, thus ensuring the long-term interests of our customers are considered.

Our asset management system provides many benefits aside from robust decision-making frameworks, including ensuring alignment to business objectives, documented processes, clarity of roles and responsibilities, continuous improvement, consistency of application and defined governance. These benefits contribute to an internal discipline that assures our customers and shareholders of an efficient approach to justified asset management and expenditure decision making that is continuously improving. The AER has previously noted the importance of these features and benefits in the context of efficient capital expenditure forecasting—in its 2019 industry practice application note, and the AER states that its asset replacement planning principles and approaches accord with good asset management practices, and that good asset management practices are often aligned with international standards of practice such as ISO 55000.²¹

Jemena's certification process was predicated by a gap analysis to identify strengths and weaknesses in consideration of both standards. The gap analysis informed a series of improvement initiative deliverables, which culminated in our ISO 55001 and ISO 27001 aligned asset management system. Each improvement initiative was progressively put into operation upon delivery at least six months before certification to ensure it satisfied requirements, was entrenched in the business and subject to continuous improvement.

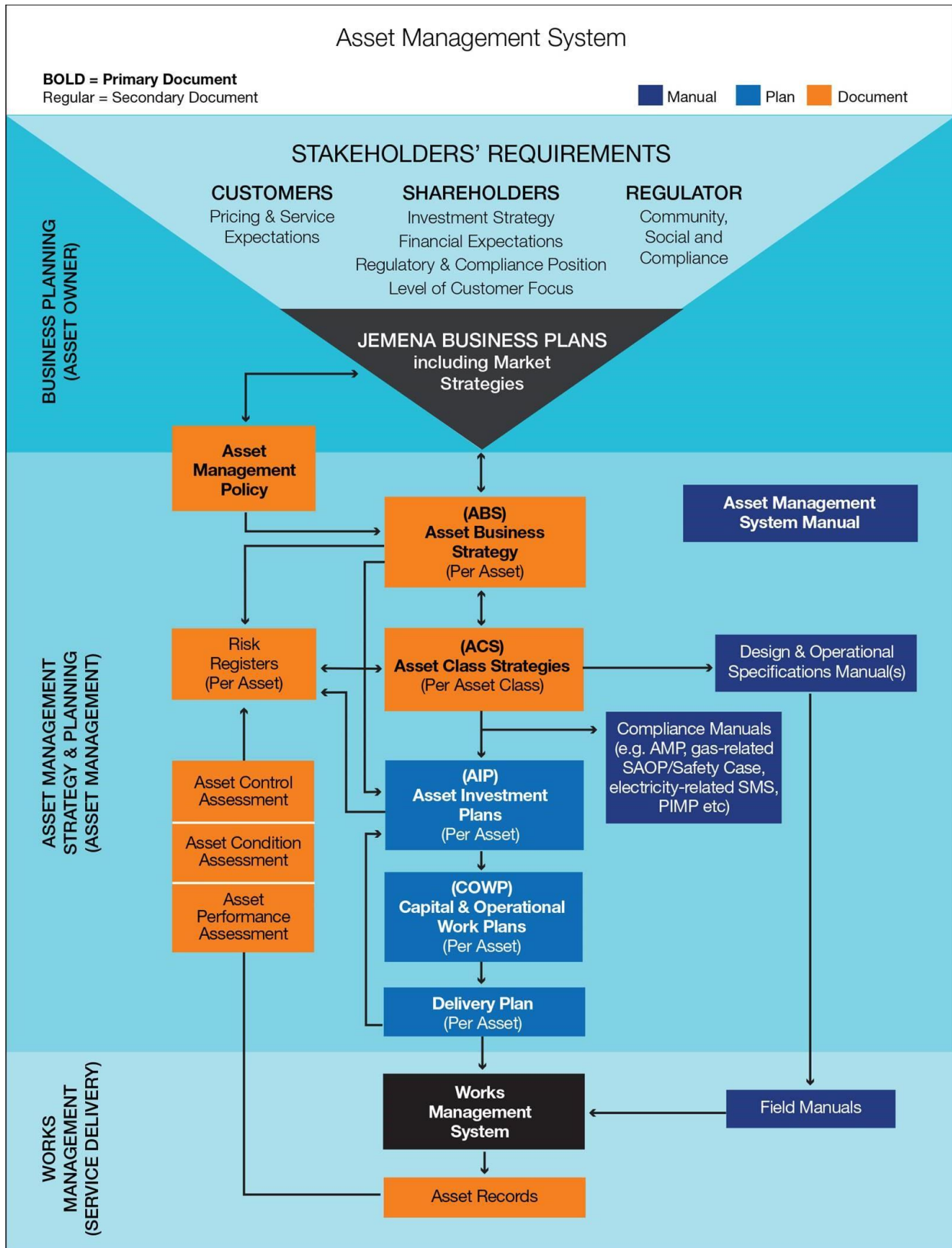
Our asset management system ensures a structured planning and approval process that aligns Jemena's Business Plan, Asset Management Policy and other strategies, objectives and plans. Figure 2–1 illustrates the

²⁰ This section relates to network assets; refer to our RIN Response – *Technology Plan* for information about non-network IT and communications assets.

²¹ AER, *Industry practice application note – Asset replacement planning*, January 2019, p. 1.

relationships between policies, procedures, objectives and plans within our asset management system. Key artefacts within our asset management system are then described in the sub-section below.

Figure 2–1: Overview of asset management system

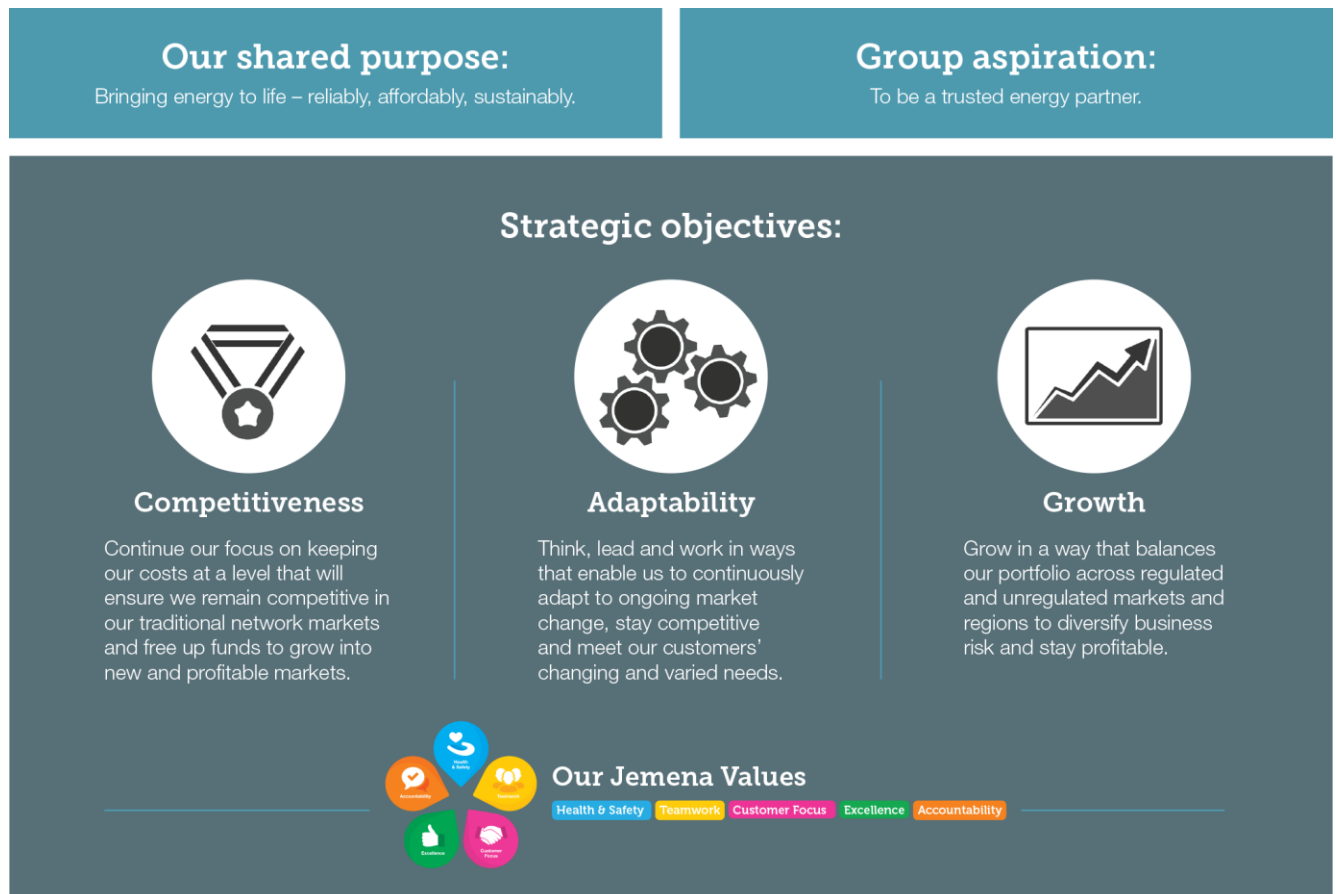


2.1 Asset management system summary

Section 1 of this document described the external drivers—most importantly, our customers’ expectations—which ultimately influence our capital expenditure. These drivers are also key inputs to our business plan, which informs the strategic direction for our Asset Management Policy, Asset Management Strategy and Objectives and Asset Management Plan. This section provides a brief overview of the our business plan.

Jemena’s purpose is to bring energy to life—reliably, affordably and sustainably—and our Group aspiration is to a trusted energy partner. To achieve our aspiration we have several strategic objectives, which are in-turn supported by our Jemena Values. Figure 2–2 summarises the Jemena Group’s business plan.

Figure 2–2: Summary of Jemena Group business plan



Informed by our business plan, we maintain an Asset Management Policy, which states Jemena’s intentions and principals for asset management applicable throughout our business. Our Asset Management Policy is provided in our response to the Reset RIN.

Within our asset management system and sitting below our business plan and Asset Management Policy, we maintain several additional artefacts, which describe how we propose to manage our assets efficiently and prudently in our customers’ long-term interests. These artefacts are summarised in Table 2–1 and further detail is provided in Appendix D section D1. This structure of artefacts reflects the best-practice elements of and complies with ISO 55001.

Table 2–1: Asset management system key artefacts

Title	Purpose
Asset Business Strategy	The JEN Asset Business Strategy translates Jemena's organisational objectives into individual asset objectives. It provides a 20-year view which informs long-term operational and asset management trends, long-term customer preferences and impact of new technologies and policy changes on our business.
Asset Class Strategies	Explains how each asset class will contribute to delivering the asset management objectives set out in the Asset Business Strategy, considering the performance, risk, age, criticality and condition of the class. In developing an Asset Class Strategy, we consider scenario analysis of various strategies (such as replacement and refurbishment decisions, deployment of non-asset alternatives, etc), to ensure asset management activities for that class are optimised to achieve the objectives. JEN has eight Asset Class Strategies.
Network Development Strategies	Provide information about capacity risks and options for economically mitigating them for specific geographic regions within our network area. Network Development Strategies analyse a range of credible alternatives and their benefits to propose a preferred option for addressing an identified network constraint. JEN currently has eight Network Development Strategies.
Asset Management Plan and Asset Investment Plan	Provides a medium-term (rolling seven-year) optimised plan for the management of assets, taking into account existing and future customer requirements and operating environments, and balancing financial constraints, commercial and business objectives, regulatory requirements and asset condition information.
Capital and Operating Work Plan	Provides itemised detail on optimised expenditure over a rolling two year time horizon for designing, constructing, operating maintaining and supporting the network.

2.2 Asset management system governance

Clear and robust governance processes are integral to the successful operation of our asset management system and the artefacts within it. Our asset management system governance processes provide decision making process structures, including roles and responsibilities, and guidance on management practices and processes relating to risk, change and documentation.

The responsibilities and authorities of critical functions within JEN are defined by our organisational structure and comprehensive accountability matrix, which maps the responsible, accountable, supporting, consulted and informed roles to processes. Ultimately, the Executive General Manager Electricity Distribution is responsible for the management, maintenance and operation of JEN's assets, and is actively involved in all aspects of our asset management system—including approval of documentation and continual review of outcomes.

Additionally, feedback from our customers and other external stakeholders guides the strategic direction of artefacts such as our Asset Business Strategy and Asset Management and Investment Plans, through to standardisation committees which consider technical matters.

Appendix D, section D2 contains further information on the governance of our asset management system, including:

- asset information management
- change management

- asset risk management
- asset management system compliance
- asset management system audit
- asset management system improvement.

2.3 References

Supporting documents included as part of our regulatory proposal or response to the Reset RIN in relation to our asset management system are listed below.

Document title	Location
Jemena Asset Management Policy	RIN Response

3. Capital planning governance and forecasting

Consistent with the goals and objectives outlined in the Jemena Business Plan and our Asset Management Policy (refer to section 2.1), we maintain a robust set of processes for planning, forecasting and delivering capital works. This section and accompanying Appendix E provide information about these key elements of our planning and governance in relation to capital expenditure.

Figure 3–1 summarises these elements of our capital planning and governance process and how they ensure our capital investments represent the most efficient means of providing the services to our customers over the long-term. This section focusses on network capital expenditure²²—refer to our RIN Response²³ – *Technology Plan* for information about non-network IT and communications capital expenditure.

Figure 3–1: Key elements of our capital planning governance and forecasting process



3.1 Capital project prioritisation

We maintain a process to prioritise and optimise the inclusion of projects within our forward program of capital works (as reflected in our forecast capital expenditure for the next regulatory period). JEN's Asset Investment

²² Note that section 3.3 covers our total capital expenditure forecast.

²³ Our response to the information sought by the AER in the Regulatory Information Notice served on 4 October 2019.

team ranks projects based on net customer benefit, challenging bottom-up project and program forecasts, and allowing interrelationships and delivery efficiencies to be considered.

As an example of this, for many of our asset replacement activities, we use Condition Based Risk Management (**CBRM**) modelling to estimate the 'health' of our existing assets and the level of future investment required to prevent this health profile from deteriorating over time. For example, for replacement expenditure, we consider an alternate top-down forecast provided by the AER's Repex model, which inherently reflects delivery efficiencies by using historic and benchmark unit costs for replacement activities and can capture interrelationships with other areas of our capital works program (such as the replacement of some assets through customer-initiated or augmentation works).

This approach also allows us to optimise the cost of our overall capital works program by coordinating delivery of projects relating to a similar location or asset (such as a zone substation), ensure timing constraints for project delivery are incorporated into our planning process, and plan the timing of long-lead time projects to minimise costs (where unique equipment or land acquisition is required). For example, our bottom-up forecasts of expenditure for non-routine zone substation rebuild projects reflect delivery and scope efficiencies associated with addressing a range of asset performance issues at once, with the timing of these expenditures optimised against risk to customers of expected unserved energy.

Refer to Appendix E section E1 for further information on our capital project prioritisation approach.

3.2 Our Project Management Methodology

We maintain a standardised Project Management Methodology (**PMM**) to guide the prudent and efficient selection and delivery of capital projects. Our PMM consists of seven sequential gates over four stages:

1. Initiate
2. Plan and define
3. Deliver
4. Close.

These gates ensure appropriate levels of management oversight at critical stages in a project's life, ensuring we deliver projects on time, cost-controlled and to the required quality, in a safe, reliable and efficient manner. Our PMM is also adaptable to projects of different levels of risk, with higher risk or more complex projects requiring additional controls.

Refer to Appendix E section E2 for further information on our PMM.

3.3 Capital expenditure forecasting

Our forecast capital expenditure for the next regulatory period consists of project and program estimates which we have developed in line with the principles set out in the Jemena Cost Estimation Methodology.²⁴ Our cost estimates employ the best available information to develop project estimates, depending on the nature and timing of the project. Refer to Appendix E section E3 for further details on our cost estimation approach.

We develop our cost estimates using the following techniques:

- top-down estimation—historical data from projects or programs with a similar scope is used to develop an estimate
- bottom-up estimation—engineering expertise is applied to develop an estimate for a specific project with a known detailed scope by considering each package of work required within the project.

²⁴ For information on our cost estimation approach for non-network IT projects, refer to our JEN Technology Plan.

Table 3–1 summarises how we have applied these methodologies to each category of our capital expenditure forecast.²⁵

Table 3–1: Summary of capital expenditure forecasting methodologies applied by expenditure category

Expenditure category	Method applied	Further explanation provided in
Replacement	Forecast for all items (except customer-initiated works) developed on a bottom-up (individual project/program) basis, with project costs developed using a combination of bottom-up and top-down estimation methods. Forecast for customer-initiated works developed on a top-down basis.	Replacement expenditure – section 4 Customer-initiated asset relocation works – section 4.11.1
Connections	Forecast for general connections developed on a top-down basis. Forecast for major customer connection projects developed on a bottom-up basis using bottom-up estimation methods.	General connections – section 5.2 Major customer connection projects – section 5.3
Augmentation	Forecast developed on a bottom-up (individual project/program) basis, with project costs developed using bottom-up estimation methods.	Section 6
Non-network – IT & communications	Forecast developed on a bottom-up (individual project/program) basis, with project costs developed using a combination of bottom-up and top-down estimation methods.	Section 7.2
Non-network – all other sub-categories	Forecast developed on a bottom-up (individual project/program) basis, with project costs developed using a combination of bottom-up and top-down estimation methods.	Sections 7.3 to 7.5

3.3.1 Independent verification of our cost estimates

To ensure our cost estimates reflect the efficient costs of undertaking the activities represented in our capital expenditure forecast, we engaged independent expert AECOM to verify our costings for six of our proposed major zone substation projects. AECOM estimated the efficient benchmark cost of each project and then compared our cost estimates against the benchmark. Overall, AECOM found that our estimates for these projects were within the industry range and in accordance with expectations for projects of this type given each project's particular requirements and constraints. AECOM's methodology and results are described further in Appendix E section E3 and our RIN Response – *AECOM ZSS Asset Replacement Programs Benchmark Report*.

3.3.2 Cost escalation

As part of our capital expenditure forecasting process, we have considered real changes in the prices of inputs used to deliver our capital works program over the next regulatory period. Accordingly, we have applied real cost escalation to internal labour within our capital expenditure forecast. The escalator we have applied to internal labour reflects the average of forecasts by BIS Oxford Economics²⁶ and Deloitte Access Economics²⁷ of wage-price indices for the utilities sector. A report from BIS Oxford Economics explaining their forecast is provided as Attachment 05-07 to our regulatory proposal. The average of these two forecasts was applied to the portion of

²⁵ NER cl S6.1.1(2).

²⁶ JEN has used BIS Oxford Economics' forecast Wage Price Index of the Victorian Electricity, Gas, Water and Waste Services ('Utilities') sector, 9 October 2019, sourced from Attachment 05-07.

²⁷ JEN has used Deloitte Access Economics' forecast Wage Price Index of the New South Wales Utilities sector, 24 June 2019, as sourced from the AER's Draft Determination for SA Power Networks.

our capital expenditure which is labour in nature, consistent with the approach described in section 5.2 of Attachment 06-01.

3.3.3 Capitalised overheads

Our total capital expenditure forecast for the next regulatory period includes an amount reflecting the capitalised portion of our overhead expenditure.²⁸ This reflects the fact that some of the activities we carry out as a business which are classified as overhead in nature are necessary to support the delivery of our program of capital works.

We categorise overheads into two types—corporate and network—consistent with the AER's preferred categories. For the next regulatory period, we will apply our new approved Cost Allocation Method (**CAM**) and will no longer be capitalising corporate overheads from 1 January 2021 (refer to section 4.5.2 of Attachment 06-01 for further information). Therefore our capital expenditure forecast for the next regulatory period only includes capitalised network overheads. To derive our forecast of capitalised overheads for the next regulatory period, we have applied the same methodology used by the AER in its final determination for JEN's current regulatory period²⁹ and:

- obtained the most recent available actual data on capitalised network overheads during the current regulatory period (calendar years 2016 to 2018)
- determined the proportions of capitalised network overheads, based on the average of calendar years 2016 to 2018, which are fixed and variable³⁰
- applied real price escalation to the fixed proportion of capitalised network overheads
- for the variable portion of capitalised network overheads, determined the average ratio (over the calendar years 2016 to 2018) of capitalised network overheads to direct capital expenditure which attracts overheads,³¹ and then applied this ratio to our forecast of direct capital expenditure attracting overheads for the next regulatory period.

This forecasting approach is consistent between Jemena's two network businesses, JEN and Jemena Gas Networks (NSW) Ltd (**JGN**).

3.4 Business case assessments

Business cases are a critical artefact within our capital planning and governance framework, as they document how each of our capital investments represents the optimal solution to a problem in terms of our customers' long-term interests. Each of our business cases:

- clearly defines a project need, including the customer implications (for example, the risk of lost supply to customers due to a degraded or constrained asset)
- outlines numerous options to address the identified need (for example, doing nothing, or implementing different network and non-network solutions at different timings)
- identifies the option which will maximise the net benefit to customers over the long-term.

Refer to Appendix E section 0 for further information on our business case assessments.

²⁸ Our approach to capitalising overhead expenditure is consistent with our *Guidance – Property, Plant and Equipment* and *Guidance – Intangible Assets*, provided in our RIN Response.

²⁹ AER, *Final decision: Jemena distribution determination, 2016 to 2020, Attachment 6 – Capital expenditure*, May 2016.

³⁰ We have adopted the AER's approach as set out in its final decision capital expenditure model for JEN for the 2016-20 regulatory period, which determined that 75 per cent of overheads are fixed.

³¹ Note there were no changes in the categories of direct capital expenditure which attract capitalised overheads between CY16-18 and the next regulatory period.

3.5 Risk management

Our robust and enduring approach to risk management is critical to sustaining our ability to achieving our business objectives and customers' long-term interests. Risk management practices are integrated into our organisational culture and embedded across a range of our asset management planning and decision-making processes—ranging from contractor management on individual projects to the development of our Asset Class Strategies. We maintain an organisation-wide Risk Management Policy in accordance with AS/NZS 31000:2018.

Refer to Appendix E, section E5 and Attachment 07-08 (*Managing Risk and Uncertainty*) for further information on our approach to risk management.

3.6 Procurement

Our procurement processes are designed to ensure that all purchases reflect the least cost option over the long-term. This is achieved through our strategic procurement approach, competitive tender processes, panel agreements with suppliers, standardised contracts and service level agreements and period contracts for the supply of network equipment to standardised specifications.

Refer to Appendix E section E6 for further information on our procurement approach.

3.7 Capital works delivery

We have a strong track record in efficiently and successfully delivering works for our distribution network. In 2018, JEN re-evaluated its capital and operating program delivery approach, which previously involved using a mix of internal and external (contractor) resources. Following this, we have moved to an outsourced model for the delivery of field works, meaning that JEN relies on contractors to deliver works rather than maintaining a field labour force itself. JEN currently has one primary contractor to provide the majority of its electricity field works. However, we may use a range of contractors to deliver significant capital projects.

We maintain a robust governance framework to monitor and control all activities undertaken by our contractors, with oversight of operations and program delivery. Our Electricity Asset Investment team is responsible for developing JEN's Capital and Operating Work Plan, which confirms the timings and costs of proposed works for a rolling two year period. The Electricity Asset Investment team is then responsible for:

- issuing statements of work to contractors
- contractor management, including reviewing and approving contractor pricing, scopes and timings, work program oversight and audits
- approving invoices for work once completed and handed over to JEN.

JEN's capital expenditure forecast for the next regulatory period represents a realistically deliverable program of works, as our primary contractor has a proven track record in successfully delivering electricity field services for JEN and other DNSPs. Furthermore, our contract allows it to subcontract work to other service providers where efficient to optimise its delivery of services to us—for example, in cases of high workloads or where specialist services such as complex civil works are required.

3.8 References

Supporting documents included as part of our regulatory proposal or response to the Reset RIN in relation to our capital planning governance and forecasting are listed below.

Document title	Location
Attachment 05-07 BIS Oxford Economics Real cost escalation report	Regulatory proposal
Attachment 07-08 Managing Risk and Uncertainty	Regulatory proposal
Jemena Cost Estimation Methodology	RIN Response
AECOM ZSS asset replacement programs benchmark report	RIN Response

4. Replacement expenditure

4.1 Summary

We need to replace existing parts of the network which have reached the end of their economic lives with their modern equivalents (or a lesser capacity asset if possible) so that we can maintain our current levels of network services, consistent with our customers' expectations.³²

Our replacement expenditure objectives:

- Meet customers' expectations that we should maintain our current levels of network reliability (including the frequency and duration of network outages) at the most efficient cost over the long term
- Manage safety, environmental, physical security and cybersecurity risks to as low as practicable³³ and comply with all applicable regulatory obligations³⁴ at the most efficient cost over the long term

Our capital expenditure forecast for the next regulatory period comprises \$211M of replacement expenditure. This represents a 10 per cent increase in replacement expenditure from the our actual expenditure during the current regulatory period.

This replacement expenditure forecast, in combination with JEN's total capital and operating expenditure forecasts, represents the most efficient level of aggregate expenditure to deliver the replacement expenditure objectives set out above. Key drivers of our replacement expenditure forecast include:

- the continuation of our ongoing program to replace (or reinforce) some large families of assets—including poles and cross arms—whose condition continues to degrade, with our focus on the assets whose failure poses the highest risks to safety and our ability to maintain current levels of service to customers
- an increase in our replacement of some specific families of assets whose health is expected to degrade in the forecast period significantly or which pose particular risks to safety and customer supply, including:
 - certain types of overhead services which no longer meet current design standards
 - replacement of low voltage (**LV**) mains with aerial bundled cable in hazardous bushfire risk areas (**HBRA**)
 - poles which are undersized for their mechanical loadings
- a shift in expenditure focus from the replacement of zone substation transformers (following a significant replacement program during the current regulatory period) to the replacement of switchgear and secondary equipment at some zone substations initially installed in the 1960s—with this equipment posing a high risk of being unable to maintain supply to customers in areas such as Coburg North, Coburg South and Footscray West
- continued strong demand from customers and other statutory authorities for the relocation or rearrangement of network assets to facilitate the construction of major public infrastructure projects.³⁵

Our replacement expenditure forecast has been developed using the engineering expertise of our Asset Management team and its detailed knowledge of our network assets and customers' requirements. This includes the condition of existing assets, the factors likely to impact the health of our network over the forecast period and expected changes in the energy usage behaviour of our customers over the forecast period.

³² In some cases, we may be able to maintain the required level of performance from an asset by replacing it with one of a lower capacity—see our case study on page 24 as an example.

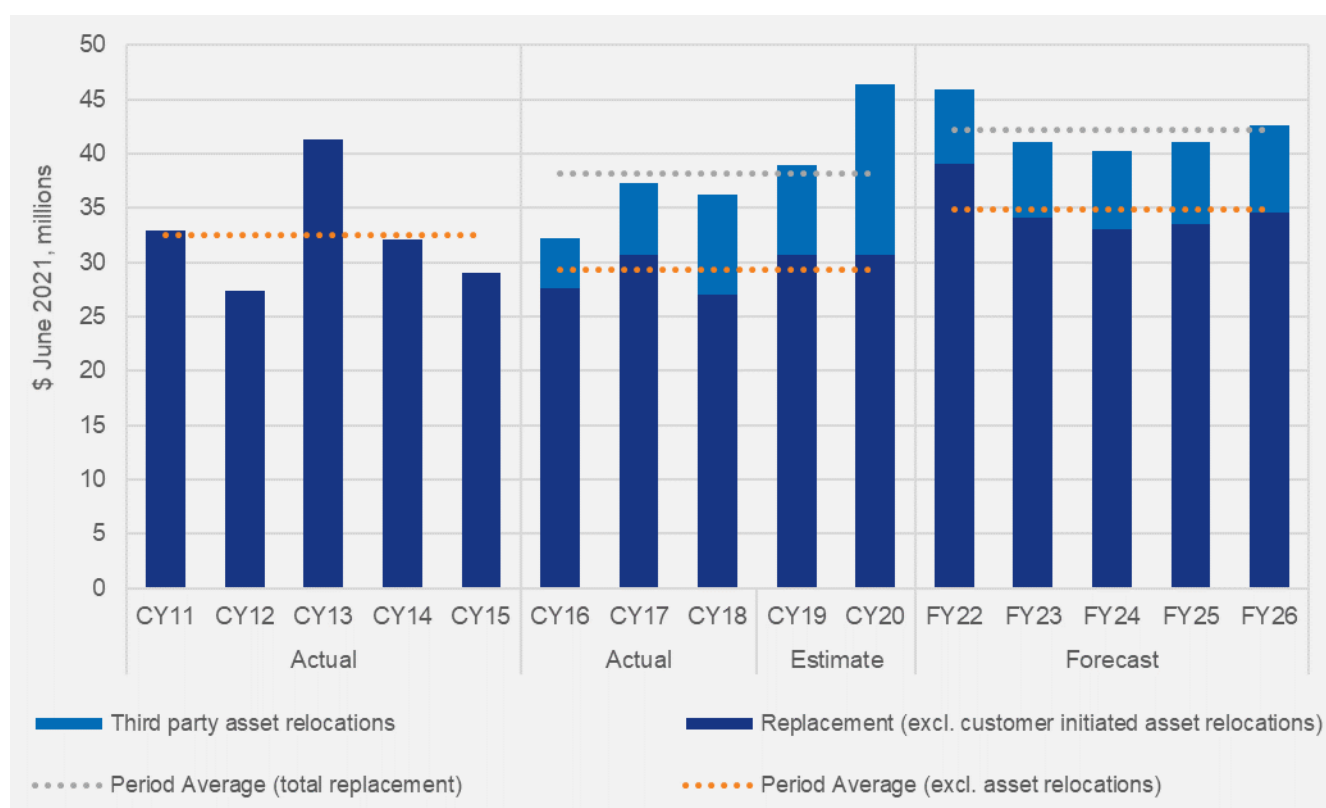
³³ Including delivering the initiatives outlined in JEN's approved Electricity Safety Management Scheme.

³⁴ Including complying with section 3.1 of the Essential Service Commission's *Electricity Distribution Code*, August 2018.

³⁵ Although a very high proportion of this expenditure is funded by requesting customers through capital contributions, this expenditure is still included in JEN's gross replacement expenditure forecast.

The expenditure drivers discussed above are reflected in our forecast replacement expenditure, illustrated in Figure 4–1, while Table 4–1 sets out our replacement expenditure forecast by RIN category.

Figure 4–1: Replacement expenditure (\$ June 2021, millions)



- (1) Although they form part of JEN's replacement expenditure actuals and forecast, third party asset relocation works are shown separately on this chart as JEN has no control over the levels of these works, and they are almost entirely customer-funded. Note that asset relocation works were not reported as part of replacement expenditure during the 2011-15 regulatory period.

Table 4–1: Forecast replacement expenditure by asset group (\$ June 2021, millions)

Replacement expenditure by asset group	FY22	FY23	FY24	FY25	FY26	Total
Poles	3.6	3.7	3.8	3.8	3.7	18.6
Pole top structures	5.1	5.1	5.2	5.2	5.3	25.9
Overhead conductors	2.2	2.4	2.7	2.5	2.3	12.1
Underground cables	1.9	1.9	1.9	1.9	1.9	9.4
Service lines	4.1	4.1	4.1	4.2	4.2	20.7
Transformers	6.7	1.6	1.6	1.7	1.7	13.2
Switchgear	5.7	4.8	5.3	5.2	5.0	26.0
SCADA, network control & protection systems						
<i>Protection systems</i>	4.1	4.3	4.0	4.7	6.1	23.2
<i>Communications</i>	0.9	1.2	0.8	0.8	0.8	4.5
<i>Other</i>	0.9	0.0	0.0	0.3	0.3	1.5
Other						
<i>Customer initiated asset relocations</i>	6.9	6.9	7.3	7.6	8.0	36.7
<i>Emergency recoverable works</i>	2.3	2.3	2.4	2.4	2.4	11.8
<i>Other assets</i>	1.4	2.6	1.3	0.9	1.0	7.2
Gross replacement capital expenditure	45.9	41.0	40.3	41.1	42.6	210.9
Capital contributions ¹	6.7	6.8	7.1	7.4	7.7	35.6
Net replacement capital expenditure	39.2	34.3	33.2	33.7	34.9	175.3

(1) Capital contributions apply to customer-initiated asset relocation works.

Economic and technical lives

We use the terms *economic life* and *technical life* throughout this document. These terms have the meanings as set out in the AER's industry practice application note on asset replacement planning:³⁶

- economic life – the age of an asset at which the total cost of providing the required level of service from the asset no longer represents the lowest long-run cost to customers of providing that required service (i.e. after considering alternatives)
- technical life – the typical expected life of an asset before it fails in service under normal operating conditions. The technical life may differ between networks (due to different operating environment factors) and between asset classes.

As explained throughout this document, the *required level of service* for our assets is generally one which allows us to meet the expectations our customers have outlined through our engagement program—that we maintain the safety, reliability and quality of our network services over the long-term.

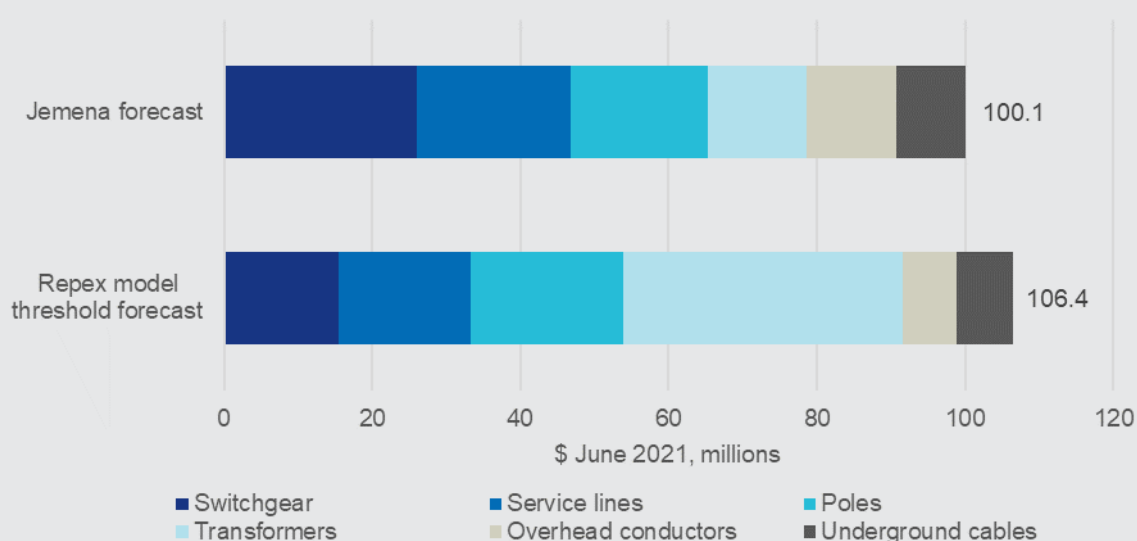
³⁶ AER, *Industry practice application note – Asset replacement planning*, January 2019.

Assessing our forecast using the AER's Repex model

We have assessed our forecast replacement capital expenditure using the AER's Repex model, in line with the AER's preferred approach.³⁷ This approach allowed us to cross-check and validate our own replacement expenditure forecast (developed on a bottom-up basis) against one developed using a top-down predictive methodology which takes into account benchmark unit costs and asset lives from other DNSPs.³⁸

We engaged independent experts Nuttall Consulting to undertake this assessment for us. This involved establishing a threshold forecast for the 'modelled' asset groups³⁹ using the AER's model and methodology by running four scenarios which use variations in the asset life and unit cost inputs to the model—including both JEN's historical and National Electricity Market benchmark asset lives and unit costs. This threshold forecast was then compared against our own replacement expenditure forecast.

Nuttall Consulting's assessment supported our forecast replacement expenditure, with our forecast for the modelled asset groups (\$100.1M) being \$6.3M lower than the threshold forecast of \$106.4M set by the AER's model. A comparison of the two forecasts is shown below.



There are some variances between the Repex model and our own replacement forecast at an asset group level, which can be expected when comparing a top-down predictive modelling approach to a bottom-up forecast. Nuttall Consulting's report noted this, stating that:⁴⁰

'the threshold amount represents the aggregate repex over the regulatory period being assessed i.e. it is not a year-by-year figure or a figure developed for each asset group or category. As such, it may be that the DNSP's forecast for some asset categories can be above the threshold forecast for those categories, provided this is offset by other categories where the DNSP's forecast is below the threshold.'

Additionally, for the two asset groups where the largest variances exist (switchgear and transformers), our own replacement forecast is heavily influenced by a significant increase in zone substation switchgear replacement next period and a significant decrease in zone substation transformer replacement next period—with both representing very lumpy, non-routine expenditures.

Refer to Attachment 05-05 for a full description of our Repex modelling assessment approach and results.

³⁷ As most recently applied in the AER's draft decisions for Energex and Ergon Energy's 2020-25 regulatory period.

³⁸ This analysis used benchmark model parameters for other DNSPs published by the AER as part of the recent Energex and Ergon draft decisions for the 2020-25 regulatory period.

³⁹ Consistent with the AER's approach, these are the Poles, Overhead Conductor, Underground Cables, Services, Transformers and Switchgear asset groups. Together, expenditure on these asset groups comprises 44 per cent of JEN's (gross) forecast replacement expenditure for the next regulatory period.

⁴⁰ Attachment 05-05, pp. 7-8.

Section 4.2 provides an overview of our asset replacement planning approach, and the sections following then provide information and our replacement expenditure forecast for each replacement expenditure asset group as set out in the AER's preferred sub-categories:⁴¹

- poles
- pole top structures
- overhead conductors
- underground cables
- service lines
- transformers
- switchgear
- SCADA, network control & protection systems
- other assets.

4.2 Our approach to asset replacement planning

We adopt a risk-based approach in our asset replacement planning, which aims to:

- optimise the total lifecycle (capital and operating) costs of asset ownership⁴²
- maximise the economic life of in-service assets through repair or refurbishment where efficient⁴³
- employ non-network solutions where possible to defer the need to replace or refurbish assets⁴⁴
- use the best available information on the actual condition of assets, the probability and consequence of their failure (the 'counterfactual' in options analysis), the forward-looking operating and maintenance costs and prospective customer demand.

To minimise the total lifecycle costs and maximise the technical life of assets, we undertake asset inspection, testing, and maintenance programs across all of our assets. In cases where the replacement of an asset can be efficiently deferred, we may undertake demand management activities; these activities form part of our operating expenditure forecast.

However, most network assets, or their components, will fail at some stage due to their condition, age or other external factors. This generally requires capital expenditure to replace a failed or deteriorated asset with one which can meet the service requirements we have of that asset⁴⁵—which, in broad terms, are for us to meet our customers' expectations that we efficiently maintain the reliability and quality of our network services over the long-term.

The expected number of significant asset failures within a population is a crucial piece of data we consider in our asset replacement planning. We can forecast this data using techniques such as Condition Based Risk Modelling (refer to section 4.2.1). For a given level of planned asset replacement activity, if the expected number of asset failures is decreasing (or increasing) then it is reasonable to conclude that the replacement program will improve (or worsen) network reliability, security and safety, all of which are related to the number of asset failures. In the

⁴¹ As specified in the Reset RIN.

⁴² For example, performing risk assessments to determine whether it is efficient to defer the replacement of an asset by undertaking additional maintenance and/or inspection activities.

⁴³ For example, using pole staking to extend the life of wooden poles instead of replacing them.

⁴⁴ For example, de-rating an in-service asset and utilising demand management to reduce the risk of unserved energy associated with deferring that asset's replacement.

⁴⁵ As noted above, in some situations there may be opportunities to replace an asset with one of a smaller capacity if this still allows us to meet our customers' service expectations.

context of our customers' expectation that we maintain the safety and reliability of our network services over the long-term, we have developed our replacement expenditure forecast to allow us to:

- avoid an increase in the number of asset failures (thus preventing a deterioration in the quality of our services that would otherwise occur)
- to decrease the number of asset failures where there are serious safety risks such as for some older overhead service lines.

When forecasting the activities and replacement expenditure required to ensure we can continue to maintain our service levels and comply with all relevant regulatory obligations, we apply two broad approaches to asset replacement planning:

- replace before failure—replace the asset in anticipation of an unrepairable failure
- replace on failure—replace the asset following an unrepairable failure.

We determine the most prudent and efficient replacement planning approach for each asset type by considering the risks associated with that asset's failure (including safety and environmental) and the criticality of the asset in supplying services to customers. Because the failure of some electricity network assets can have safety and service reliability consequences, we replace many asset types just prior to the end of their technical lives to avoid in-service failures. Our Electricity Safety Management Scheme further explains our approach to condition-based replacement of critical assets to avoid asset failure and the associated safety risks, as opposed to planning for them to fail while in service.

It should be noted that regardless of the replacement approach adopted, decisions on whether to undertake a like-for-like replacement or with an asset of higher or lower capacity are made using the best available information about future demand requirements. Additionally, in some very limited circumstances, we may be able to avoid replacement of an asset entirely where there is no longer any requirement for that asset, and not replace it upon failure.

Using risk-based replacement planning to reduce capital expenditure – a case study

Structural economic and urban development changes have led to significant diversity in customer demand growth across different areas of our network, including some industrial areas where peak demand has been in decline. Although network capacity constraints may not be an issue in areas such as Broadmeadows, we still need to ensure that the customers who are supplied receive a level of network service in the future which is consistent with today—this includes planning to address the risk to supply posed by deteriorating assets.

Our Broadmeadows zone substation currently has four transformers, two of which are in poor condition and are at high risk of failure in the next regulatory period, causing significant outages for customers. After considering detailed information on the condition and likelihood of failure of these transformers, we employed our risk-based replacement planning approach to assess several options to address the risks identified. In our risk-based planning approach, we treat the failure of the degraded transformers (which carries a supply consequence for customers) as the counterfactual case against which all other options are compared. As well as considering like-for-like replacements, we explored options including replacements with smaller capacity units, replacement of only one transformer and non-network alternatives. Through this planning approach, we determined that replacement of only one transformer and keeping another as a 'hot spare' represented the option with the highest net benefit (including providing a higher net benefit than the counterfactual case of the transformers failing) for customers based on forecast level of demand and the risk to supply.

Importantly, where we plan to replace a critical asset before failure, we assess asset condition to optimise the timing of our replacement decisions and avoid the early replacement of assets that are likely to continue to perform

as required. We apply multiple methods to estimate the likely time of failure of an asset and therefore optimise replacement timing, including:

- assessing the condition of assets through field inspections and testing
- analysing asset failure history to identify emerging trends.


These methods are reflected in our approach to applying Condition Base Risk Management to our asset replacement planning, as discussed below.

4.2.1 Condition Based Risk Management modelling

We use a modelling tool known as Condition Based Risk Management (**CBRM**) to aid our replacement planning assessments for several key asset types including poles, crossarms, distribution and zone substation transformers and distribution and zone substation switchgear. CBRM is a model which uses asset information to provide a quantitative risk evaluation across an asset population, including the expected number of asset failures and economic risk values for each asset class. We have applied these models to guide our asset replacement planning to ensure we efficiently continue to maintain the safety and reliability of our network at current levels.

CBRM Health Index explained

CBRM calculates a Health Index of an asset, which is a means of combining information on the asset's age, environment and duty, as well as specific condition and performance information, to give a comparable measure of condition for individual assets in terms of their proximity to end of life and probability of failure. The conceptual relationships between Health Indices, asset remaining life and probability of failure are illustrated below.

Condition	Health Index		Remnant life	Probability of failure
Bad	10		At end of life (<5 years)	High
Poor			5-10 years	Medium
Fair			10-20 years	Low
Good	0		>20 years	Very low

The Health Index reflects the extent of asset degradation using the following scale:

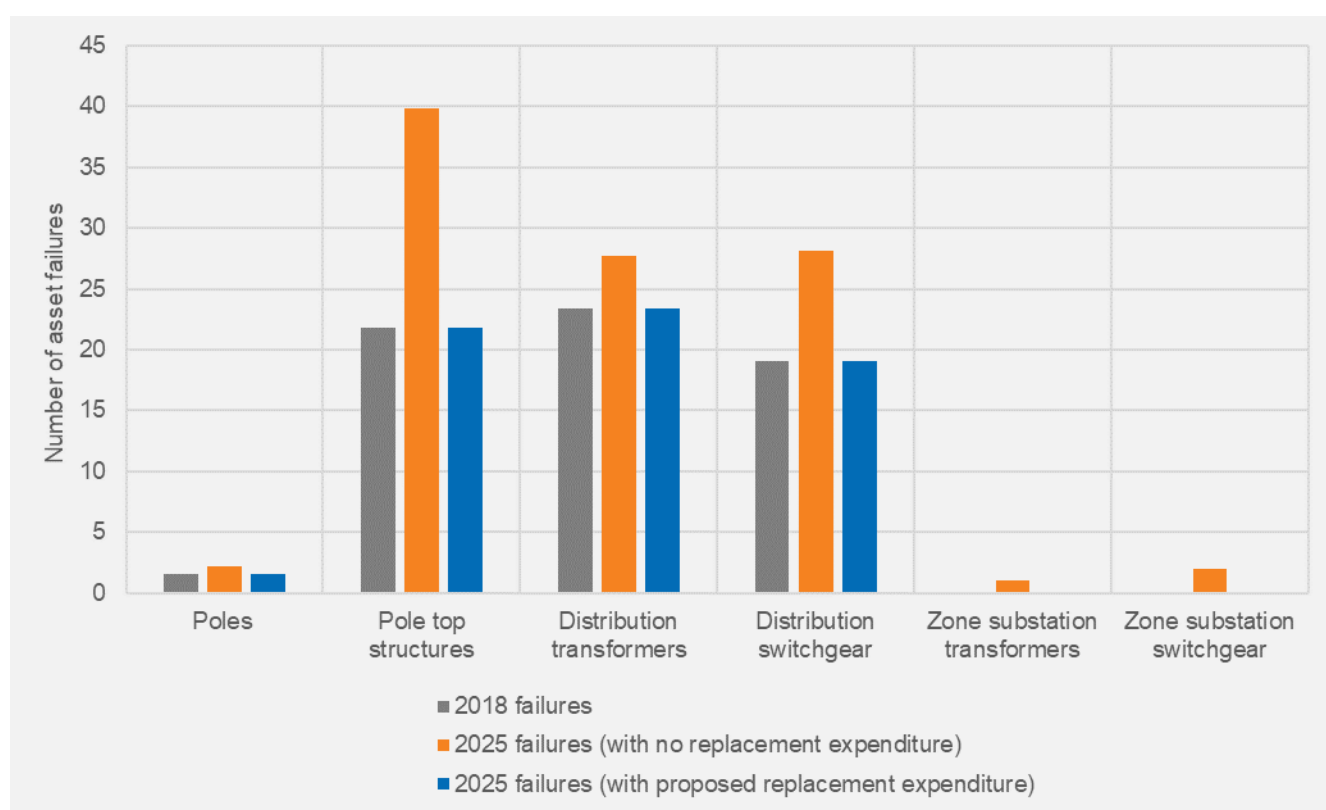
- Low values (in the range 0 to 4) represent some observable or detectable deterioration at an early stage. This may be considered as normal aging, i.e. the difference between a new asset and one that has been in service for some time but is still in good condition. In such a condition, the probability of failure remains very low, and the condition and probability of failure would not be expected to change significantly for some time.
- Medium values of health index, in the range 4 to 7, represent significant deterioration, with degradation processes starting to move from normal aging to processes that potentially threaten failure. In this condition, the probability of failure, although still low, is just beginning to rise and the rate of further degradation is increasing.
- High values of health index (>7) represent serious deterioration; i.e. advanced degradation processes now reach the point that they threaten failure. In this condition, the probability of failure is now significantly raised and the rate of further degradation is likely to continue increasing.

The methodologies we use to develop the forecast of replacement volumes do not require an explicit representation of the distribution of the asset life (via the parameterisation of a normal distribution or some other function, as is required by the AER's Repex model). However, our CBRM modelling does implicitly allow for the variability in the life of across the asset population (through the input of other data which represents the condition and service environment of assets) and also reflects Perks' equation⁴⁶ to estimate the probability of failure of an asset, and in turn, calculate the risks of asset failure over the analysis period.

Figure 4–2 summarises outputs from our CBRM models for key asset classes, showing our number of failures (in 2018) compared against the predicted number of failures in 2025 under two scenarios—not replacing any assets, and replacing assets as planned in our replacement expenditure forecast.

⁴⁶ This can be used to estimate the probability of an asset failure based on an asset's age or condition.

Figure 4–2: Number of failures by asset class



This chart shows that without any asset replacements over the forecast period, the failure rates would increase significantly across these asset classes, for example, with the number of pole top failures rising by 83 per cent. These levels of asset failures associated with not replacing any assets as planned would render us unable to meet our customers' expectations that we maintain our current levels of network reliability. Importantly, this chart also shows that the predicted number of failures in 2025, if replacements are carried as planned in our replacement expenditure forecast, is consistent with 2018 failure levels—demonstrating that our replacement expenditure forecast is designed to maintain network reliability and safety at current levels.

4.2.2 Routine and non-routine asset replacement

Within our replacement expenditure program, we have both routine and non-routine works, reflecting differences in the nature of the assets, their replacement needs and our forecasting approaches. For groups containing low cost and high volume assets, we generally plan and undertake asset replacements on a routine basis—that is, we produce aggregate replacement volume forecasts for the asset population (based on information about asset condition) and apply a unit cost of replacement to derive our replacement expenditure forecast. For groups containing high cost and low volume assets, we adopt a detailed risk-based analysis which involves forecasting replacement needs and costs on an asset-specific basis.

The sub-sections below describe in further detail how we develop our replacement expenditure for each asset group, including how we have forecast both routine and non-routine expenditure. Additional information is also provided in the asset class strategy, business case and strategic planning documents relevant to each asset group, as referred to in each sub-section. Section 3.3 and Appendix E summarise our cost estimation methodology, which sets out the process we use to develop detailed cost estimates which underpin our capital expenditure forecast.

4.2.3 References

Supporting documents included as part of our regulatory proposal or response to the Reset RIN for our replacement expenditure approach are listed below.

Document title	Location
Attachment 05-05 Nuttall Consulting AER repex modelling	Regulatory proposal

4.3 Poles

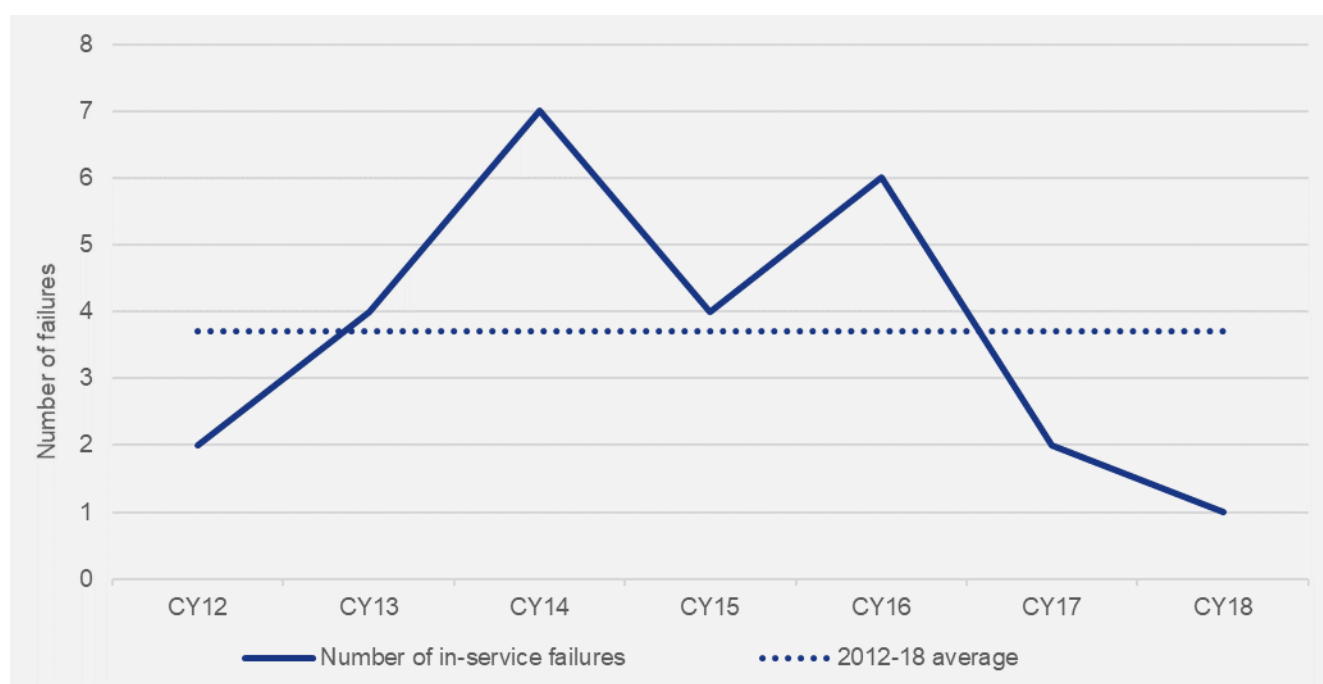
Poles are used to support the overhead conductors which transmit electricity around our distribution network, in addition to carrying other assets such as public lighting and telecommunications cable. We own approximately 80,000 poles (excluding dedicated public lighting poles).

Poles are a high criticality asset. The failure of a pole can pose serious safety and bushfire ignition risks and is also a cause of supply interruptions for customers. These outcomes are inconsistent with our customers' expectations that we maintain our current levels of network reliability, as well as with our obligations to protect the safety of the public around our assets. Poles therefore need to be either reinforced or replaced before failure,⁴⁷ while any poles which have failed in service also require replacement. Poles can fail due to a wide range of factors, including wood rot, termites, corrosion and vehicle impact, and their condition deteriorates over time with exposure to the external environment.

We would be unable to maintain our current level of network reliability in the future if there was an increase in the number of in-service pole failures. Our pole replacement expenditure forecast has therefore been developed to allow us to continue to replacing all poles before failure, based on assessments of their condition. This will avoid an increase in our in-service pole failure rate, which has averaged less than 4 per year between 2012 and 2018, as illustrated in Figure 4–3.

⁴⁷ This can be physical failure (where the structure cannot support its own weight or the weight of overhead infrastructure), functional failure (where a pole's remaining strength is assessed as insufficient to safely perform its required function) or footing failure (where the foundation or ground condition does not provide sufficient support and causes the pole to lean).

Figure 4–3: Number of in-service pole failures



Consistent with the AER's replacement expenditure category definitions, JEN's forecast (and historic reported) pole replacement expenditure includes:

- pole reinforcement (e.g. staking of wooden poles to extend their lives)
- the replacement of pole top structures when undertaken in conjunction with a pole replacement.⁴⁸

Our forecast replacement expenditure on poles (including reinforcement) includes the continuation of our replacement program which targets undersized poles—which do not meet current technical standards and pose a safety risk. Our annual forecast replacement expenditure for poles is set out in Table 4–2.

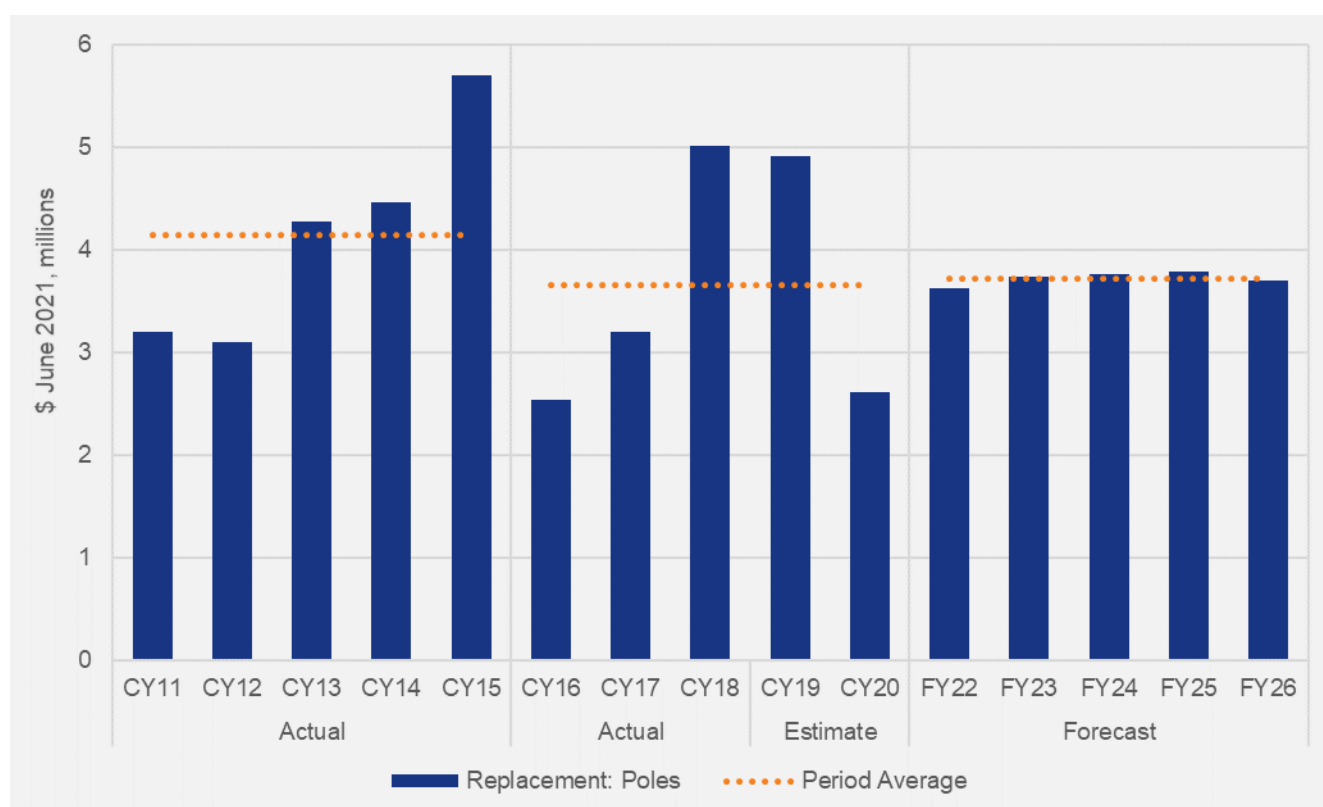
Table 4–2: Forecast replacement expenditure – poles (\$ June 2021, millions)

	FY22	FY23	FY24	FY25	FY26	Total
Condition-based reinforcement and replacement program	2.6	2.6	2.6	2.6	2.6	12.9
Undersized pole reinforcement and replacement program	1.1	1.2	1.2	1.2	1.1	5.7
Total	3.6	3.7	3.8	3.8	3.7	18.6

Under our forecast expenditure, we expect to reinforce 4,900 poles and replace 1,000 poles during the next regulatory period. While our forecast pole replacement volumes are in line with those of the current regulatory period, we are forecasting an increase in the number of pole reinforcements (from 3,455 during the current regulatory period), as discussed in section 4.3.1. Despite this increase in volumes, our forecast is in line with our average annual expenditure during the current regulatory period, as shown in Figure 4–4.

⁴⁸ JEN often replaces a pole top structure at the same time it replaces a pole, due to the significant synergies and cost efficiencies in undertaking both jobs at the same time.

Figure 4–4: Pole replacement expenditure (\$ June 2021, millions)



4.3.1 Condition-based reinforcement and replacement program

We are proposing to continue our ongoing programs of work to reinforce or replace poles which have reached the end of their technical life and can no longer be maintained economically. Individual poles which require reinforcement or replacement are identified through routine pole inspections, which we regularly undertake in accordance with Victorian regulatory requirements.⁴⁹

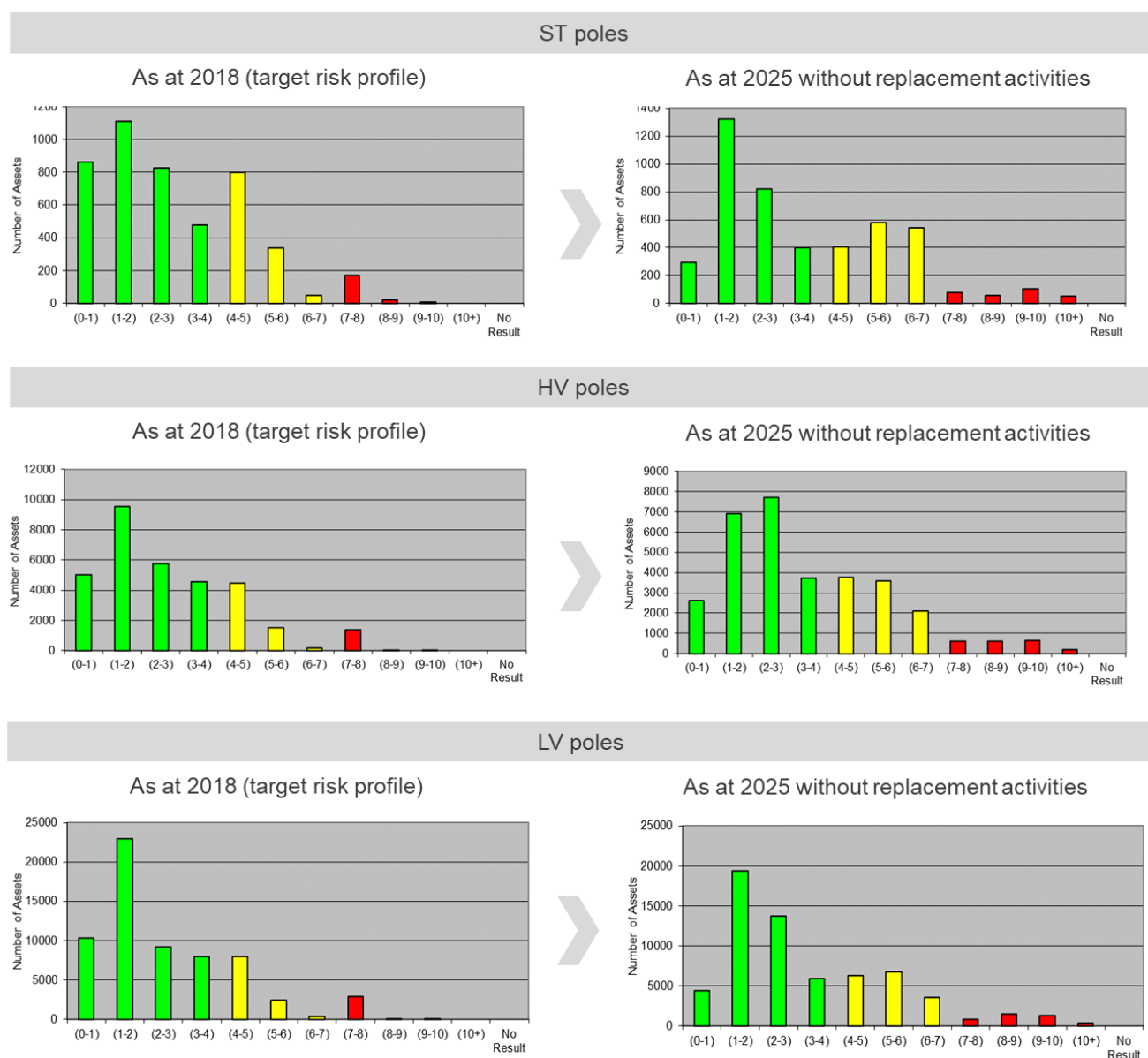
In developing our forecast, we considered options such as reducing pole replacement expenditure from current levels, undertaking age-based (rather than condition-based) replacement, performing replacements instead of life-extending reinforcements, and running assets to failure.

Our CBRM analysis shows that if we were to cease carrying out our pole replacement program in the next regulatory period, the condition of these assets would continue to deteriorate, resulting in a significantly higher proportion of poles being in their end-of-life phase and having a high probability of failure. This potential for degradation if no replacements are undertaken as planned is illustrated in the right column of Figure 4–5. Our condition-based replacement programs are designed to broadly maintain the current level of risk associated with this asset class (illustrated in the left column of Figure 4–5), therefore, allowing us to maintain our current level of reliability, which is forecast to result in a health index profile as at 2025 similar to that which we have as at 2018.

In aggregate, our proposed condition-based pole expenditure is consistent with our expenditure during the current regulatory period. Our proposed volume of pole replacements is in line with the number we expect to undertake during the current regulatory period (forecast 8 per cent increase), although we are forecasting a 42 per cent increase in the volume of pole reinforcements we will need to undertake during the next regulatory period. This increase in pole reinforcement activities is designed to target (and prevent further deterioration of) poles with a CBRM Health Index of 6 or greater, particularly LV poles as illustrated in Figure 4–5.

⁴⁹ *Electricity Safety (Bushfire Mitigation) Regulations 2013* s 7(1)(i) sets out maximum inspection intervals, and requires more frequent inspection of assets in HBRA.

Figure 4–5: Health Index profile for all poles as of 2018



4.3.2 Undersized pole reinforcement and replacement program

Our pole replacement expenditure forecast also includes us continuing our program of replacing (or reinforcing) poles which were constructed to design standards of the day but no longer meet current standards or requirements, posing safety and supply reliability risks. Our forecast aims to continue addressing two issues:

- replacement or staking of undersized poles – following several pole failures during a major storm in 2008, we identified some LV poles whose natural girth (without externally-influenced decay) is less than the minimum tabulated girth for a serviceable pole today. These poles have an elevated risk of failure due to their inadequate ability to support required mechanical loadings, and, before the previous regulatory period, we implemented a policy to replace or reinforce all undersized LV poles. As at December 2018 we had approximately 2500 of these undersized poles. Our forecast capital expenditure will allow us to address all remaining undersized LV poles by the end of the next regulatory period.

- replacement of poles with high voltage (HV) raiser brackets – in some areas where new HV lines were rolled out above existing LV circuits and poles, previous supply authorities had installed steel HV raiser brackets on existing (shorter) LV poles to maintain required line clearances (rather than replacing the LV poles with taller poles). As we now use steel HV crossarms rather than wood (reducing the risk of pole-top fires, as explained in section 0), steel HV raiser brackets pose an unacceptable safety risk to line workers due to their potential to become energised. Our forecast capital expenditure will allow us to continue replacing remaining affected poles with a standard HV pole once its wooden crossarm reaches the end of its economic life.

4.3.3 References

Supporting documents included as part of our regulatory proposal or response to the Reset RIN for our forecast pole replacement capital expenditure are listed below.

Document title	Location
Distribution Asset Class Strategy	RIN Response
Network Performance Plan	RIN Response
Bushfire Mitigation Plan	RIN Response

4.4 Pole top structures

Pole top structures include the cross-arms, insulators, insulator ties and other equipment used to attach conductors to poles. We currently have around 113,000 cross-arms.

Pole top structures need to be replaced before failure to mitigate safety and customer supply risks. Pole top structures can fail due to a variety of reasons, but most commonly deterioration over time. The failure of pole top structure components can result in a loss of supply to customers, high-voltage injections (causing customer property damage) and fire starts. These outcomes would be inconsistent with our customers' expectations that we maintain our current levels of network reliability, as well as with our obligations to manage safety risks associated with our assets. Unless the overhead circuit is no longer required, the only way of mitigating against the risk that a cross-arm will fail is to replace it with a new cross-arm.

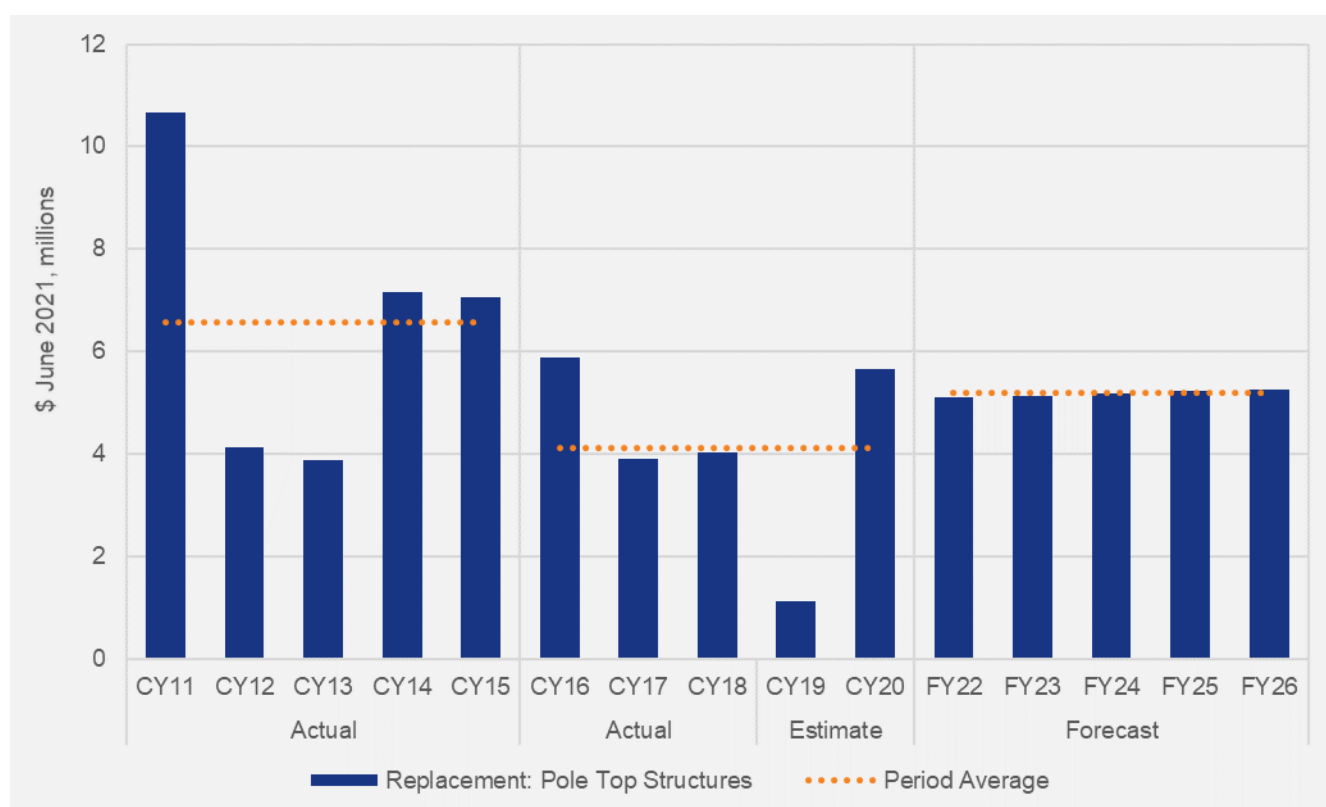
We have proposed two replacement programs for pole top structures:

- a condition-based program of works, targeting those assets with the highest risk of in-service failure
- a risk-based targeted replacement program, specifically designed to replace wooden cross-arms with newer steel cross-arms to reduce the risk of pole top fire ignition.

Under our forecast expenditure, we expect to replace over 7,200 cross-arms (an increase from 5,962 during the current regulatory period)⁵⁰ in addition to other pole top equipment. As shown in Figure 4–6, our forecast expenditure on pole top structure replacement represents an increase from our expenditure during the current regulatory period consistent with our forecast increase in replacement volumes. The primary driver of this increase is our condition-based replacement program, discussed in section 4.4.1, however this increase is also partly a function of our deferral of some replacement expenditure during the current regulatory period based on assessments of actual asset condition.

⁵⁰ These volumes reflect the number of cross-arms we expect to replace, however our volumes reported in our RIN Response also include the replacement of equipment such as insulators.

Figure 4–6: Pole top structure replacement expenditure (\$ June 2021, millions)



Our replacement expenditure forecast for poles is set out in Table 4–3,⁵¹ while the sections below provide further information about each of our forecast pole replacement programs.

Table 4–3: Forecast replacement expenditure – pole top structures (\$ June 2021, millions)

	FY22	FY23	FY24	FY25	FY26	Total
Condition-based replacement program	3.4	3.4	3.5	3.5	3.5	17.3
Risk-based pole top fire mitigation program	1.7	1.7	1.7	1.7	1.7	8.6
Total	5.1	5.1	5.2	5.2	5.3	25.9

4.4.1 Condition-based replacement program

We are proposing to continue our program of replacing the cross-arms and other pole top equipment which is at the highest risk of failure during the next regulatory period and which can no longer be maintained economically. Individual assets which require replacement are identified through our asset inspection program.

We have undertaken CBRM analysis to consider how the levels of risk associated with assets in this class are impacted as the assets deteriorate over time. The right column of Figure 4–7 illustrates the forecast deterioration of the health of these assets over the next regulatory period without intervention (i.e. if replacement activities are not undertaken). A future decrease in health and therefore increase in the number of pole top structure failures would make it unlikely that we could maintain our current level of network reliability. Our pole top structure replacement expenditure forecast will allow us to continue to replace the pole top structures which pose the highest risk of failure or fire start, based on assessments of their condition, age and operating circumstances. This level of replacement activity will allow us to broadly maintain the current level of risk associated with this asset

⁵¹ Consistent with the AER's replacement expenditure category definitions, JEN's forecast (and historic reported) pole top structure replacement expenditure relates only to the independent replacement of pole top structures (i.e. those that are *not* replaced in conjunction with the pole they are attached to).

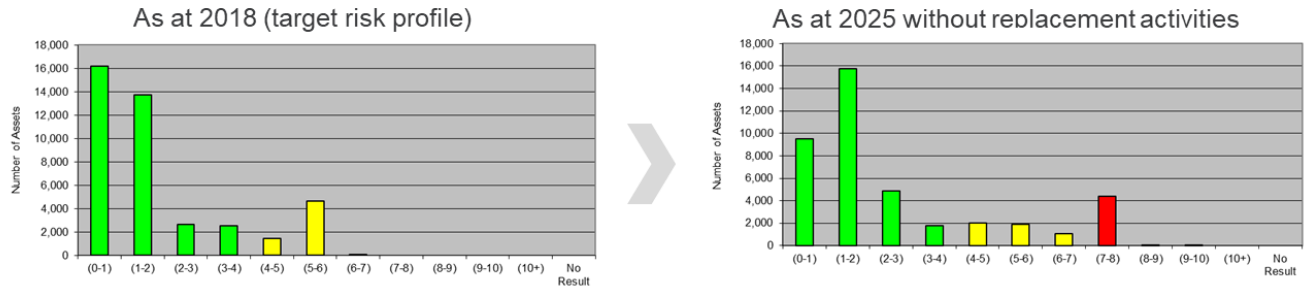
class (as illustrated in the left column of Figure 4–7, therefore maintaining our current network service levels) and efficiently manage fire start risks.

In developing our forecast, we considered options to reduce replacement activity from current levels, undertake age-based (rather than condition-based) replacements and running assets to failure. When compared to our proposed approach of maintaining current pole top structure replacement activity levels, these alternatives either resulted in a higher total cost to customers or did not address the issues and risks identified.

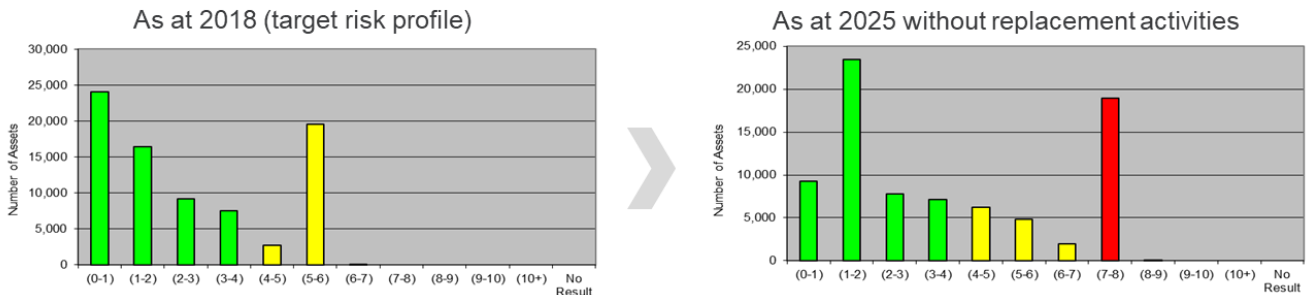
Our proposed expenditure for this program represents an increase from the current regulatory period due to the need to replace cross-arms with a current CBRM Health Index above 5 and which would become significantly deteriorated during the next regulatory period if left unaddressed, as illustrated in Figure 4–7. LV cross-arms are the most significant driver of this increase, with over 20,000 cross-arms having a Health Index greater than 5 as at 2018.

Figure 4–7: Pole top structure health index profiles

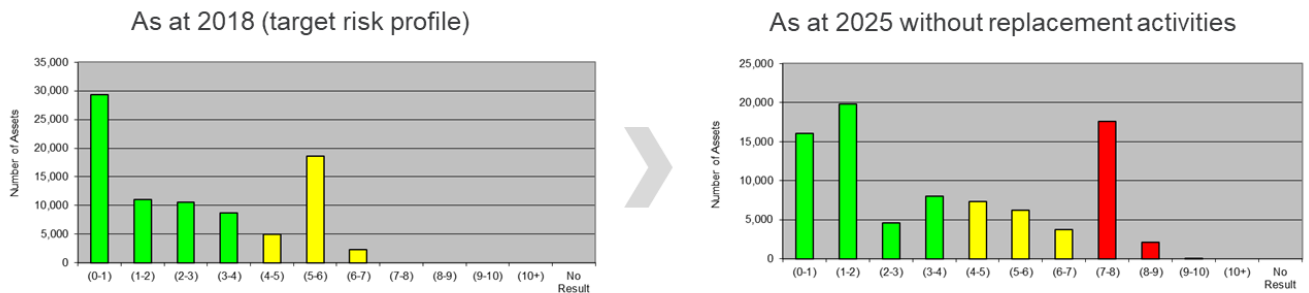
ST & HV cross-arms



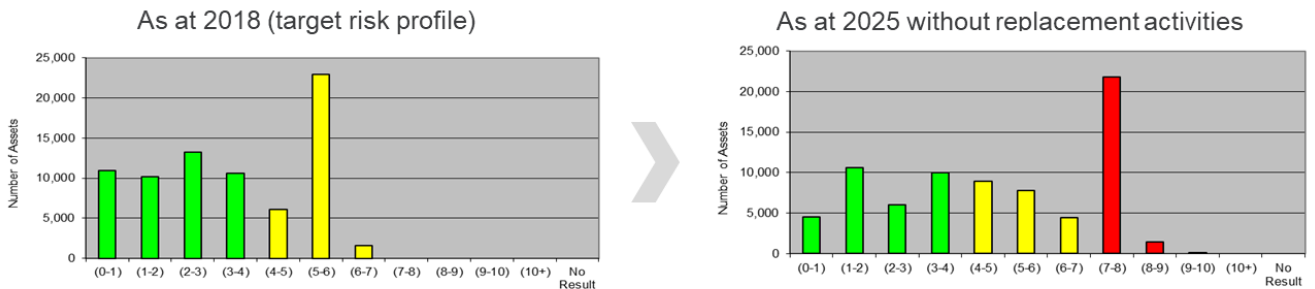
ST & HV insulators



LV cross-arms



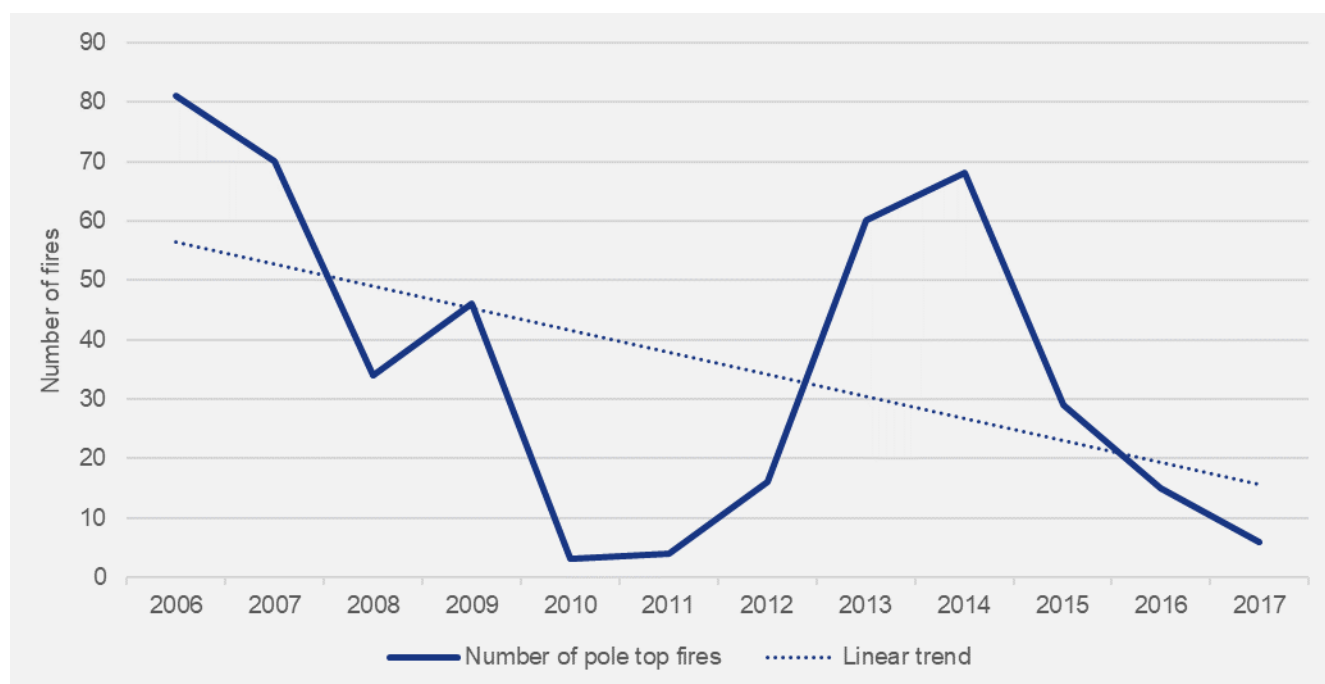
LV insulators



4.4.2 Risk-based pole top fire mitigation program

Our forecast also includes expenditure to continue undertaking our targeted program of cross-arm replacement in areas which are at a higher risk of bushfires, to reduce the risk of pole top fire starts. We commenced this program in 2000, and so far have completed the removal of all wooden HV cross-arms in areas designated as HBRA. Although the number of pole top fires can vary significantly between any given years due to environmental and weather conditions, we have seen a downward trend in aggregate over the past decade as we've undertaken our pole top fire mitigation program, as illustrated in Figure 4–8.

Figure 4–8: Pole and crossarm fires



Due to the severe consequences of a pole top fire and the effectiveness of our program in reducing fire start risk to date, we propose to continue this program throughout the next regulatory period, consistent with our 2020 Bushfire Mitigation Plan. Under this program, we identify specific assets for replacement based on analysis of our historic pole top fire starts, including the geographic location of the asset and the types of equipment involved. For example, we propose to target high pollution locations (industrial areas and main roads) in specific areas such as Yarraville, Footscray, Coburg and Reservoir, and wooden cross-arms in poor condition where they are used with particular types of insulators which are known to be more likely to contribute to a fire start.

4.4.3 References

Supporting documents included as part of our regulatory proposal or response to the Reset RIN for our forecast pole top structure replacement capital expenditure are listed below.

Document title	Location
Distribution Asset Class Strategy	RIN Response
Network Performance Plan	RIN Response
Bushfire Mitigation Plan	RIN Response

4.5 Overhead conductors

This category of assets includes the conductors used to transport electricity on the overhead parts of our network (but excludes service lines between the network and customers' properties, as is covered in section 4.7), as well as equipment such as connectors. Our distribution network has conductors which comprise around 5,000 km of overhead circuits, and which are made of various materials depending on the voltages they carry (ranging from low voltage to sub-transmission) and the era in which they were installed.

Overhead distribution assets are significantly less expensive to construct than underground alternatives. However, they have a higher visual impact on the community and generally provide less reliable service as they are more susceptible to environmental and other external interference.

Conductors are a high criticality asset, as their failure can pose serious safety and fire ignition risks (particularly in HBRA) in addition to customer supply interruptions and damage to customer property. Some types of conductors, when in poor condition, pose a significant safety risk to our crews and therefore cannot be worked on live, which results in additional (planned) customer supply interruptions and increased operational costs. The condition of overhead conductors degrades with use and over time, affected by factors such as corrosion and wind vibration (they may also fail due to external influences, such as trees falling on lines). Degradation in conductor condition is not repairable and therefore, replacement is required before failure.

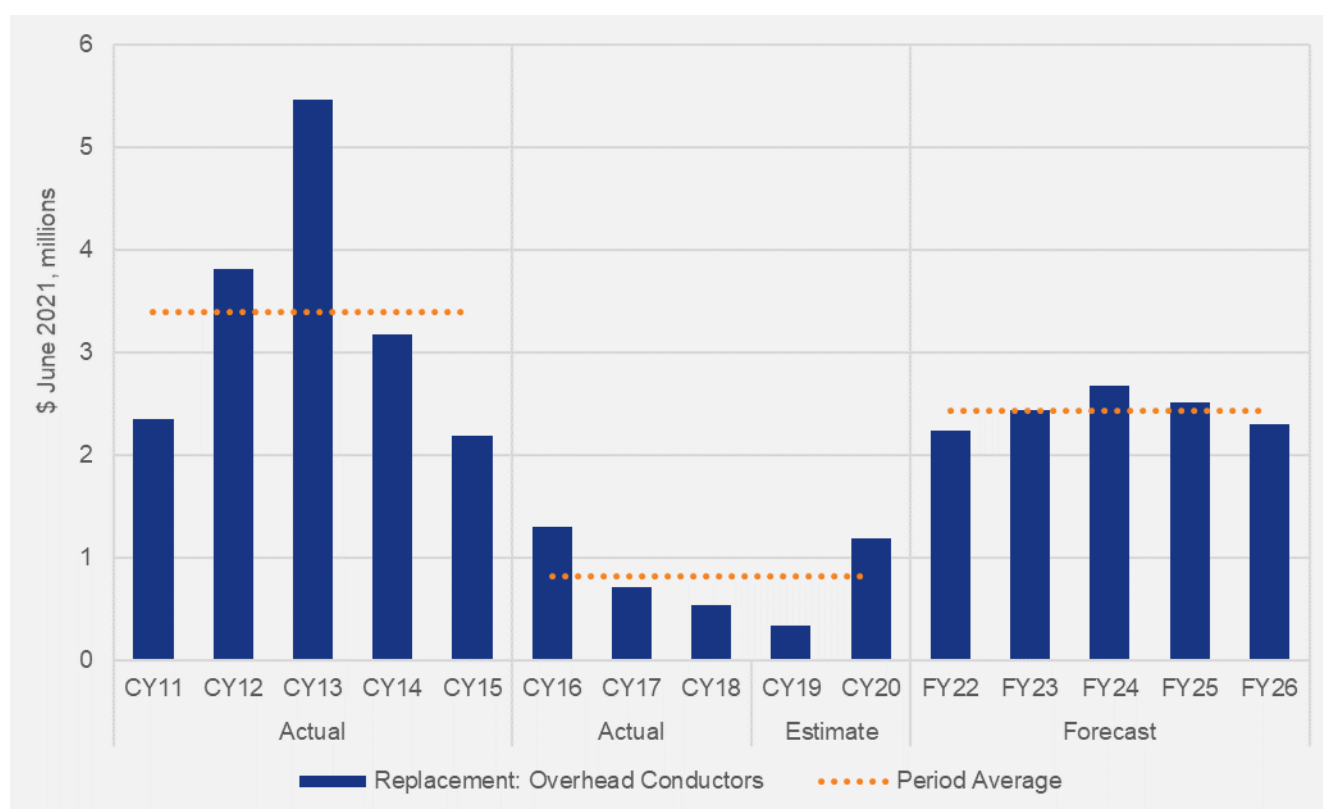
We are proposing two broad programs as part of our forecast overhead conductor replacement capital expenditure:

- condition-based replacement of overhead conductors (and associated equipment) which are at the end of their economic lives
- risk-based replacement of LV conductors in HBRA to reduce bushfire ignition risk.

Trends in our overhead conductor expenditure are shown in Figure 4–9. Our forecast replacement expenditure on overhead conductors represents an increase from the current regulatory period's expenditure levels, due to:

- a reversion to a higher levels of conductor replacement activity (closer to the long-term average of our expenditure) in the next regulatory period based on the health of this asset class. This follows our higher spend during the 2011-15 regulatory period (largely driven by the need to address legacy risks associated with these assets), which allowed us to manage risks and undertake fewer replacements during the current regulatory period
- an increase in activity due to our commencement of a program to remove LV mains in HBRA (refer to section 4.5.2).

Figure 4–9: Overhead conductor replacement expenditure (\$ June 2021, millions)



Our replacement expenditure forecast for conductors is set out in Table 4–4, while the sections below discuss our two forecast replacement programs for overhead conductors.

Table 4–4: Forecast replacement expenditure – overhead conductors (\$ June 2021, millions)

	FY22	FY23	FY24	FY25	FY26	Total
Condition-based replacement programs	1.2	1.4	1.6	1.5	1.2	6.9
Removal of LV mains in HBRA	1.0	1.0	1.0	1.0	1.1	5.2
Total	2.2	2.4	2.7	2.5	2.3	12.1

4.5.1 Condition-based replacement program

We are proposing to continue our replacement program to avoid in-service asset failure for overhead conductors based on the assessment of their condition (through our asset inspection program) and fault history information. Under this program, we will also continue replace equipment such as connectors known to represent an elevated level of risk to realise or leverage synergies associated with concurrent maintenance or refurbishment works on other assets nearby.

This program is designed to allow us to maintain our current level of risk associated with these assets into the future, allowing us to meet our customers' expectations that we maintain our current levels of network service reliability. We use information about age, conductor type and historical failure rates to identify the assets whose condition indicates a need for replacement.

4.5.2 Risk-based bushfire mitigation program

Consistent with our 2020 Bushfire Mitigation Plan, we propose to commence a program to remove all LV mains located in HBRA (as defined by the Country Fire Authority under Victorian electricity safety regulations) as a targeted way of efficiently reducing fire ignition risk. This program follows on from HBRA bushfire mitigation activities we have undertaken in previous years, including the removal of all Single Wire Earth Return lines, removal of all HV wooden cross-arms, replacement of all non-tension conductor connections and replacement of all non-preferred overhead services.

To date, we have removed 1.5 km of LV mains in Sunbury, Bulla, Gisborne, Gisborne South and Meadow Heights. Our program involves the progressive replacement of all bare LV conductors in HBRA (currently 39 km remaining) with alternative solutions such as installing small pole-mounted transformers and servicing customers directly from that pole or installing insulated LV aerial bundled conductors. In some cases, underground LV mains and services may also represent the most efficient replacement of bare LV overhead conductors. The removal of bare LV conductors also involves the removal of wooden LV crossarms, further reducing fire ignition risk.

4.5.3 References

Supporting documents included as part of our regulatory proposal or response to the Reset RIN for our forecast overhead conductor replacement capital expenditure are listed below.

Document title	Location
Distribution Asset Class Strategy	RIN Response
Network Performance Plan	RIN Response
Bushfire Mitigation Plan	RIN Response
Electric Line Clearance Plan	RIN Response

4.6 Underground cables

This category includes the cables used to transport electricity on the underground parts of our network (but excludes service lines between the network and customers' properties), as well as pits and pillars. Our network includes cables which comprise around 2,000 km of underground circuits (over 35,000 individual sections), ranging from low voltage to sub-transmission.

Underground cables have a lower visual impact on the community than overhead networks and operate with a higher level of reliability as they are less susceptible to environmental and other external interference. However, their construction and maintenance are considerably more expensive than overhead network assets.

The failure of an underground cable can pose a severe safety risk in some cases, particularly where cable insulation has completely broken down or in the event of the failure of an outdoor cast iron cable termination box. Cable failure can also cause the loss of supply to customers. The customer supply risks associated with underground cable failure vary depending on the cable's voltage. Low and high voltage cables have a lesser asset criticality as they can be repaired relatively quickly and network switching can be used to minimise customer impacts. However, some sub-transmission cables (particularly oil-filled cables installed in between the 1930s and 1960s) pose a high risk due to lengthy repair times.⁵² During the current regulatory period, we have taken advantage of opportunities to proactively replace oil-filled sub-transmission cables as part of third-party initiated asset relocation works and works at West Melbourne Terminal Station. As we consider further replacements are a lower priority in the short term, we have not included any sub-transmission cable replacements in our forecast capital expenditure for the next regulatory period. However, we expect our expenditure to replace these assets will increase in the years following the next regulatory period.

⁵² For example, damage caused by a third party to one of our oil-filled sub-transmission cables during the current regulatory period led to it being out of service for several months and could have significantly impacted supply reliability to a large number of customers if this event had occurred during summer when demand was higher.

Underground cables and their associated equipment need to be replaced before failure to mitigate safety and customer supply risks, and assets which have failed in-service also require replacement. Underground cables most commonly fail due to the breakdown of their insulation, caused by factors such as water ingress or physical damage.⁵³

We are proposing to continue our longer-term replacement program for underground cable assets based on our asset inspection program (for equipment where reactive testing can be carried out or cable termination boxes and pits which can be visually inspected) and asset performance and fault data. Assets which cannot be efficiently inspected based on their supply criticality and risk profile (largely LV cables) are run to failure.

We also plan to continue our ongoing program targeting replacement of HV cable terminations housed in cast iron boxes throughout older areas of the network. These have previously failed and present a public safety risk. We have experienced seven failures of these terminations since 2007. We have replaced all 22 kV terminations (which are the most critical) and all 6.6 kV terminations will be removed as part of our Preston conversion program. Our replacement forecast for the next regulatory period, therefore, includes expenditure to remove all 100 remaining 11 kV CABUS terminations. We also propose to replace some HV cable terminations housed in fabricated metal boxes. While less critical than cast iron termination boxes, these assets can fail due to corrosion or moisture ingress.

Together, these replacement activities are designed to allow us to maintain the current level of risk associated with these assets, allowing us to maintain our existing network service levels. As shown in Figure 4–10, our forecast level of expenditure is broadly in-line with our average annual expenditure in previous regulatory periods.

Figure 4–10: Underground cable replacement expenditure (\$ June 2021, millions)

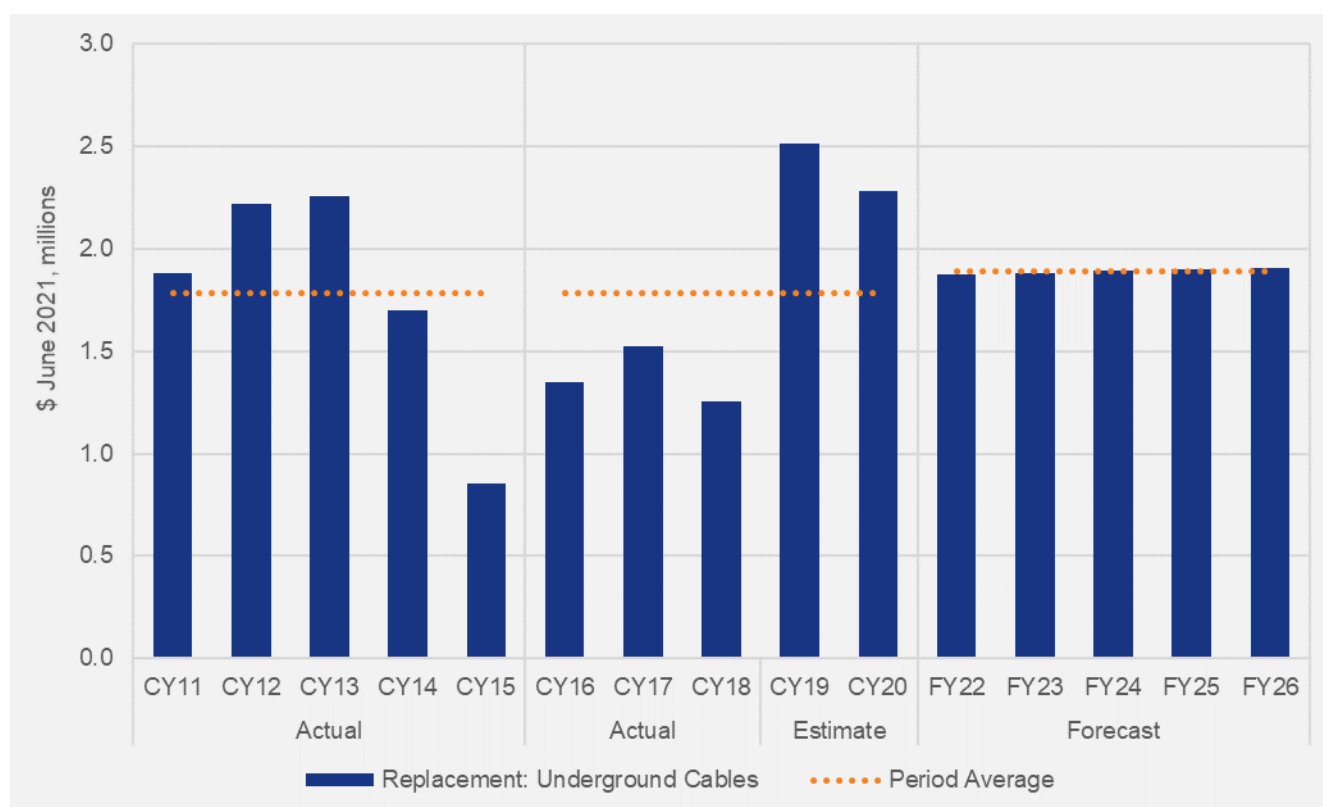


Table 4–5 sets out our underground cable expenditure for the next regulatory period.

⁵³ Note that cable failure due to damage by third parties is covered under our emergency recoverable works sub-category (within 'other replacement expenditure'), set out in section 4.11.2.

Table 4–5: Forecast replacement expenditure – underground cables (\$ June 2021, millions)

	FY22	FY23	FY24	FY25	FY26	Total
Cable replacement	1.2	1.2	1.2	1.2	1.2	5.9
Cable termination replacement	0.7	0.7	0.7	0.7	0.7	3.5
Total	1.9	1.9	1.9	1.9	1.9	9.4

4.6.1 References

Supporting documents included as part of our regulatory proposal or response to the Reset RIN for our forecast underground cable replacement capital expenditure are listed below.

Document title	Location
Distribution Asset Class Strategy	RIN Response
Network Performance Plan	RIN Response

4.7 Service lines

Service lines form the connection between the distribution network and a customer's point of supply. This asset class includes overhead services, as well as associated hardware such as termination clamps, brackets and connectors. While assets such as LV overhead services are individually one of the least expensive items on the distribution system, as an asset class, their volume and therefore, value is significant.

We currently have around 170,000 services. Several different types of services (materials and designs) have been installed since the 1930s and many remain in place today. However, several of these older technologies are no longer considered suitable to remain in service due to the safety risks they pose—we refer to these types of services as 'non-preferred'. Non-preferred service lines comprise 50 per cent of those currently in service.

Service lines need to be replaced ideally before the time they fail, as they are not repairable. Services generally fail due to the deterioration of insulation material, corrosion (causing a lack of earth bonding) and degradation of anchoring fixtures. The risk of failure for some non-preferred service types is higher due to existing flaws in their design or materials.

The failure of an overhead service can interrupt the customer's supply (though the impact of a single service's failure is insignificant from the perspective of the overall network, as they generally only supply one customer each and repair times are relatively short), and also carries fire ignition risks in some areas.

We therefore replace overhead service lines in the following circumstances:

- replacement of non-preferred service lines with current standard aerial bundled cable (**ABC**) types, utilising data on failures of similar assets in similar circumstances
- replacement upon notification of damage to a service or service termination
- replacement where inspection (which is often based on notification through advanced metering infrastructure (**AMI**) analytics) and then on-site testing indicates the service is defective
- replacement in conjunction with other pole replacements, pole top assembly or conductor work (such as planned replacement activities)

- where a service line does not achieve the minimum ground clearance requirements prescribed by the Electricity Safety (Installations) Regulations 2009.

During the next regulatory period, we propose to continue our program of replacing all non-preferred overhead services with their modern equivalents (mitigating safety risks), and we expect to replace all non-preferred services by 2030. Once this program is completed, our replacement expenditure on service lines is expected to reduce. Together with our replacement of services that have developed faults or are identified as at risk of failure through our inspection activities, these replacement programs will allow us to maintain the current level of risk associated with these assets, therefore allowing us to maintain our existing network service levels.

Figure 4–11 illustrates longer term trends in our service line replacement expenditure, and shows that our forecast expenditure represents an increase from the current regulatory period. During the current regulatory period, we modified our approach to replacing services by actively employing AMI data to identify high-impedance neutral services (one indicator of significant deterioration), and prioritised the replacement of these. This program of replacements offset some of our planned non-preferred service replacements, however for the next regulatory period we are forecasting a return to a level close to our 10-year average of expenditure on service replacements—from replacing 18,472 services during the current regulatory period to approximately 27,000 during the next regulatory period. This includes higher volumes of replacements under our non-preferred replacement program which will address several safety and condition issues in addition to high-impedance neutrals.

Figure 4–11: Service line replacement expenditure (\$ June 2021, millions)

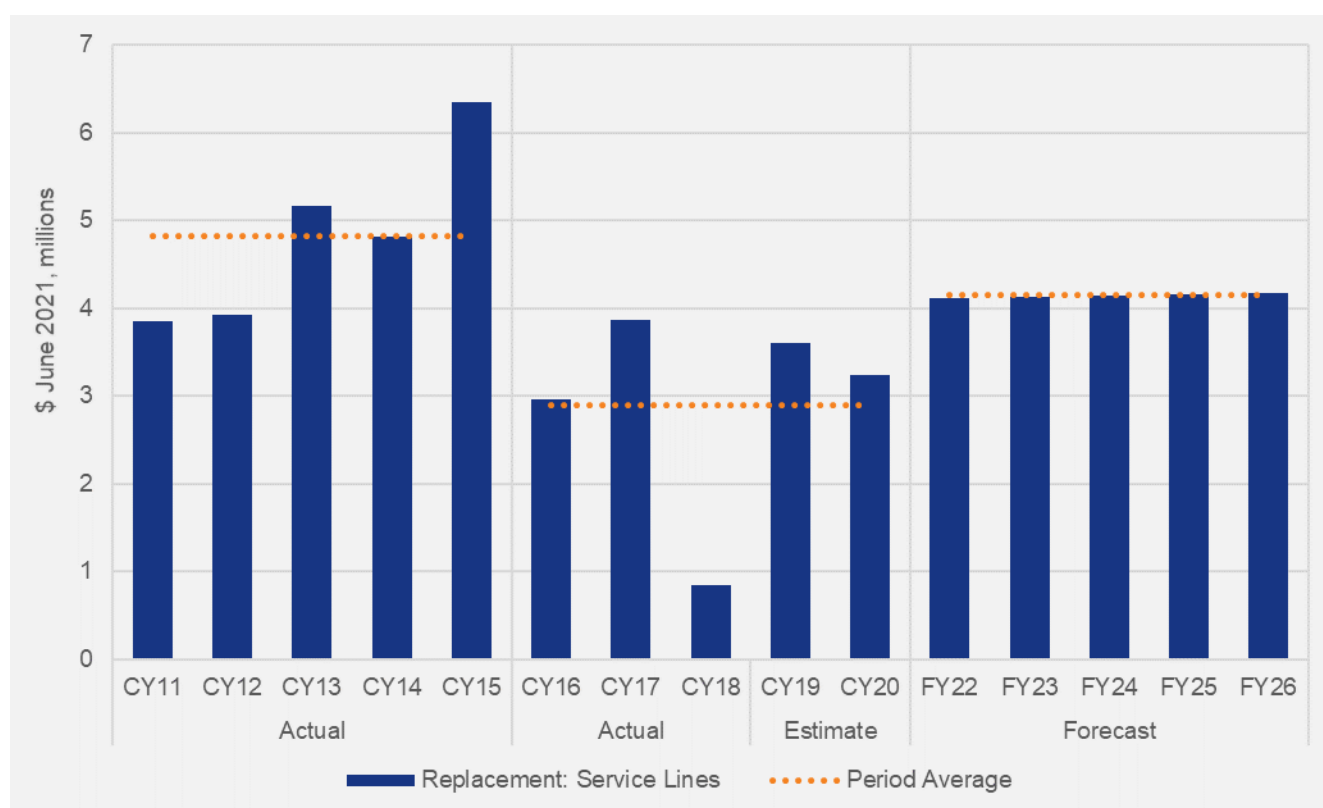


Table 4–6 sets out our forecast replacement expenditure for service lines in the next regulatory period, while the sections below discuss our condition-based and non-preferred service replacement programs.

Table 4–6: Forecast replacement expenditure – service lines (\$ June 2021, millions)

	FY22	FY23	FY24	FY25	FY26	Total
Condition-based replacement program	0.9	0.9	1.0	1.0	1.0	4.8
Non-preferred service replacement program	3.2	3.2	3.2	3.2	3.2	16.0
Total	4.1	4.1	4.1	4.2	4.2	20.7

4.7.1 Condition-based replacement program

Under our asset inspection program, we inspect and test LV overhead services at three- or four-year intervals (for hazardous and low bushfire risk areas, respectively), in line with regulatory obligations.⁵⁴ We also conduct visual inspections of services for mechanical integrity to leverage synergies with concurrent vegetation management, height measurement and maintenance activities. All services identified through inspection or testing activities as defective are replaced with their modern equivalent (aerial bundled cable).

4.7.2 Non-preferred service replacement program

Non-preferred service types which still exist on our network include bare or open wire, red lead, neutral screened and twisted wire services. All LV overhead services have an expected technical life of 40 years, and a significant portion of the asset population will exceed this age during the next regulatory period (with these being the non-preferred service types).

The population of non-preferred services currently poses the following risks:

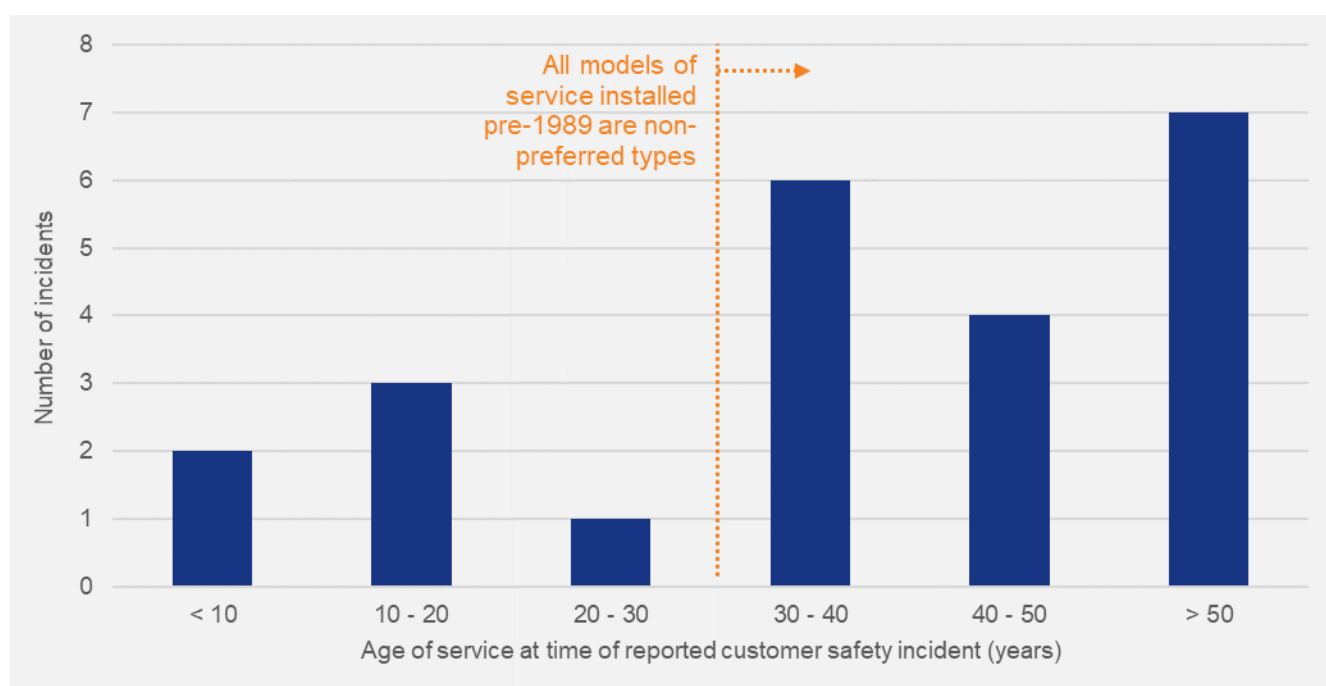
- safety risks to customers caused by deteriorated service neutrals
- fire-starts due to overhead service failure
- failure to comply with ground clearance regulations.⁵⁵

We commenced this program in 2010 in response to a growing number of customer safety incidents. Our analysis of incidents has determined that non-preferred service types are primarily responsible for neutral service test failures and resulting safety incidents. This is also evident from analysis of the age of services at the reported time of the safety incident, with Figure 4–12 showing that the majority of incidents occurred on services older than 30 years. This is notable given that all LV overhead service types installed prior to 1989 (more than 30 years ago) are of the non-preferred type, with only the current ABC type having been installed since 1989.

⁵⁴ The *Electricity Safety (Installations) Regulations 2009* and *Electricity Safety (Bushfire Mitigation) Regulations 2013*.

⁵⁵ As set out in the *Electricity Safety (Installations) Regulations 2009*.

Figure 4–12: Age of service at time of reported customer safety incident



The objective of our non-preferred service replacement program is, therefore, to address the safety risks listed above by replacing all non-preferred services with our current standard ABC type, and we expect to achieve this by 2030. This will:

- reduce the risk of electrical shocks to customers by addressing the deteriorating non-preferred service population
- minimise the potential for fire starts
- rectify non-compliant low overhead services.

In developing this program, we considered alternatives including not proactively replacing non-preferred services and replacing higher or lower volumes per annum (therefore completing the removal of all non-preferred services in a shorter or longer timeframe). We consider that continuing to proactively replace a similar number of services as we have during the current regulatory period represents an optimal balance between the costs of this program and the need to mitigate the safety risks posed by these assets.

4.7.3 References

Supporting documents included as part of our regulatory proposal or response to the Reset RIN for our forecast service line replacement capital expenditure are listed below.

Document title	Location
Distribution Asset Class Strategy	RIN Response
Network Performance Plan	RIN Response

4.8 Transformers

Transformers convert the voltage of power between different levels as it moves around our network. This sub-category of expenditure covers two types of transformers which have different replacement drivers:

- transformers located inside zone substations, which convert power from sub-transmission to high voltage, and whose replacement is non-routine in nature
- distribution transformers located throughout the distribution network on poles or in kiosks or other structures, which convert high voltage to low voltage, and whose replacement is routine.

We currently have around 6,500 distribution substations and 66 zone substation transformers.

Zone substation transformer failure is relatively rare (around 1 in 15 years), and can be caused by factors including insulation or connector deterioration, overloading or through-faults from other network equipment. Zone substation transformers are critical assets. The failure of a zone substation transformer can cause significant customer outages—a typical urban zone substation has three transformers supplying more than 10,000 residential customers, and in some cases up to 30,000 customers. The failure of a zone substation transformer also carries safety and environmental risks, such as oil spillage and possible fire. Our approach to the lifecycle management of zone substation transformers is, therefore, to undertake inspection and maintenance activities to efficiently optimise their economic life and to explore opportunities to extend the life through activities such as refurbishment where economic to do so, but to eventually replace them before an in-service failure to mitigate against the safety and customer supply risks described above.

Distribution transformers can fail due to similar reasons, such as deterioration, overload or through-faults. However, when compared to a zone substation transformer, distribution transformers are less critical, and their failure is relatively low risk, generally only causing the loss of supply to a small number of customers. Our approach to the lifecycle management of distribution transformers is therefore usually to replace them reactively (after an in-service failure), noting also that some distribution transformers may at times be replaced before the end of their technical life with a unit of larger capacity due to load growth (however this is considered augmentation expenditure, as discussed in section 6).

Figure 4–13 shows long-term trends in our transformer replacement expenditure. Our expenditure for the next regulatory period represents a significant decrease from the current regulatory period. We are coming to the end of a significant peak in zone substation transformer replacements in recent years—only two are forecast to be undertaken during the next regulatory period, compared to 10 during the current regulatory period. This lower volume of zone substation transformer replacements is the main driver of this reduction in forecast transformer replacement expenditure, with distribution transformer replacement volumes and expenditure in line with those of the current regulatory period.

Figure 4–13: Transformer replacement expenditure (\$ June 2021, millions)

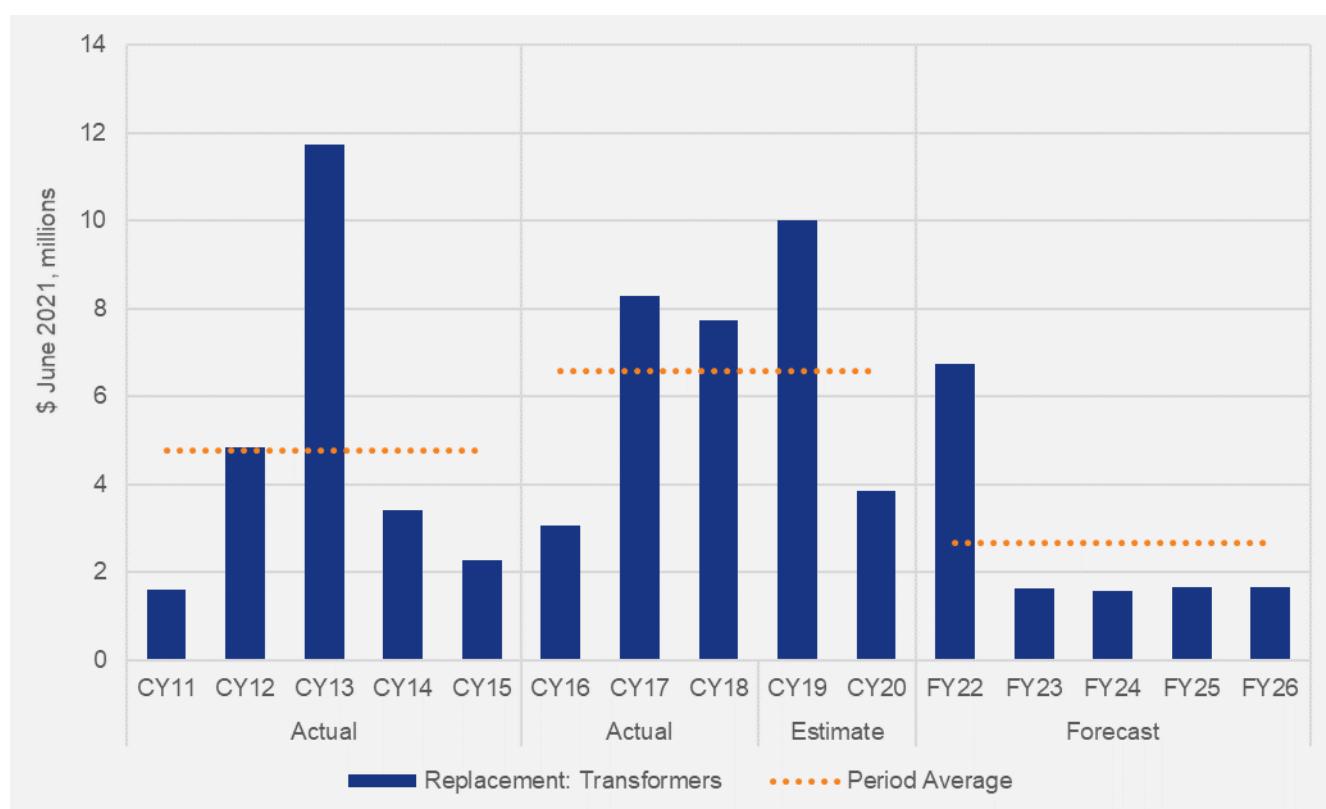


Table 4–7 sets out our forecast replacement expenditure for transformers. Sections 4.8.1 and 4.8.2 describe our proposed replacement expenditure for zone substation and distribution transformers respectively.

Table 4–7: Forecast replacement expenditure – transformers (\$ June 2021, millions)

	FY22	FY23	FY24	FY25	FY26	Total
Zone substation transformers	5.2	0.1	0.0	0.1	0.1	5.6
Distribution transformers	1.5	1.5	1.5	1.5	1.5	7.6
Total	6.7	1.6	1.6	1.7	1.7	13.2

4.8.1 Zone substation transformers

As explained above, we employ a condition-based non-routine replacement planning approach for our zone substation transformers. This approach is a prudent asset management approach given these assets' high criticality, relatively small population and a relatively high level of detailed condition information available about individual transformers. Our replacement expenditure forecast includes expenditure to continue our approach of replacing zone substation transformers to mitigate against the significant consequences of in-service failures. We propose to continue targeting the replacement of units based on detailed condition assessments, safety and environmental risks and the level of customer supply risk if a failure was to occur—this includes considering network capacity constraints (or lack thereof) in our replacement planning.

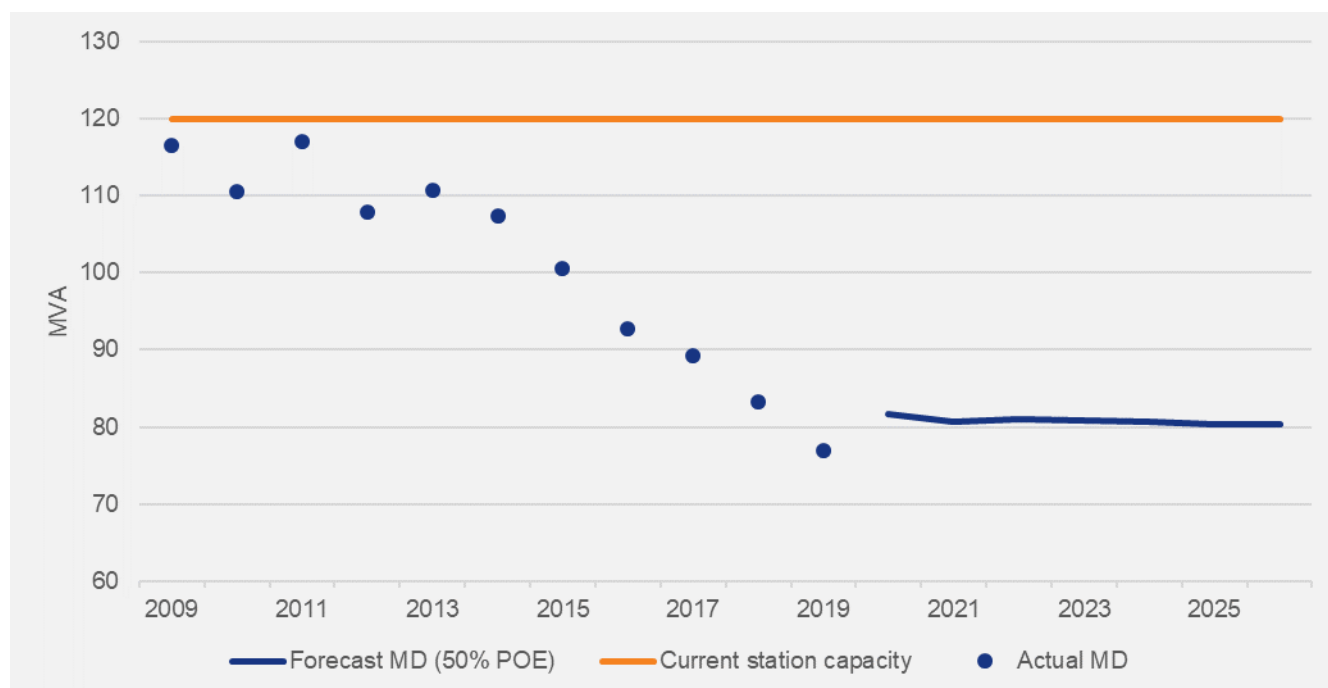
During the next regulatory period, we are proposing two zone substation transformer replacement projects, at Broadmeadows and Heidelberg. Our replacement of 3 per cent of our zone substation transformer fleet during the next regulatory period is a significant decrease from the 15 per cent replaced during the current regulatory period.

Broadmeadows zone substation

Broadmeadows zone substation supplies 14 HV feeders in the areas of Broadmeadows, Meadow Heights, Jacana and Campbellfield. It currently has four transformers, with transformers No. 1 and 2 exhibiting extensive deterioration based on analysis of the degrees of polymerisation⁵⁶ of their paper and are over 46 and 51 years old respectively. These transformers will be at high risk of failure early in the next regulatory period. A typical response to these condition issues under a non-risk based planning approach might have been to replace both deteriorated transformers on a like-for-like basis, in addition to potentially taking the opportunity to replace the No. 3 Broadmeadows zone substation transformer (which currently exhibits moderate deterioration but is over 50 years old) and leaving the No. 4 transformer (no major condition issues) in service.

However, under our risk-based replacement planning approach, we considered options other than like-for-like replacement, which is particularly relevant given the shutdown of some sizeable industrial customer loads in Broadmeadows supply area and low forecast growth in the area's maximum demand. Our assessment of the transformer utilisation at Broadmeadows indicated that while it was around 95 per cent utilised eight years ago, the closure of customers such as Ford's Campbellfield plant has seen maximum demand fall from 117 MW to approximately 80 MW (below 70 per cent utilisation), as illustrated in Figure 4–14. This provides us with the opportunity to de-rate the station, noting the need for us to also consider future possibilities such as new customers connecting in the area (such as if the old Ford site was redeveloped).

Figure 4–14: Broadmeadows zone substation – maximum demand



Options we considered to address the risks posed by the deteriorated transformers included:

- doing nothing (customers bear the risk of loss of supply)
- increasing maintenance and monitoring
- refurbishing transformers
- rewinding transformers
- replacing one, two or three of the transformers (including keeping a hot-spares)
- transferring load to reduce load at risk

⁵⁶ Degree of polymerisation (DP) is a measure of the effectiveness of a transformer's insulation. Lower DP values suggest a higher likelihood of an internal fault developing in the transformer. Two of the Broadmeadows transformers have DP values approaching 200, a level indicative of the end of a transformer's technical life.

- deploying batteries or demand management to reduce load at risk.

Our analysis of these options demonstrates that some of these options, such as maintenance and monitoring or refurbishment, would not address or lower the risk faced by customers in the event of transformer failure. Others, such as deploying non-network alternatives or undertaking a transformer rewind, were uneconomic due to their high costs relative to the risk reduction benefits delivered.

Having assessed these options, we have proposed expenditure to replace only one transformer and leave the other as a hot-spare, which will allow us to maintain a similar level of network risk in light of forecast maximum demand while still representing a saving compared to replacing both transformers on a like-for-like basis.

Heidelberg zone substation

Heidelberg zone substation currently has two transformers supplying 8,800 customers on seven HV feeders. Uniquely among the surrounding areas, Heidelberg zone substation is islanded as its supply area operates at 11kV, and therefore there is no transfer capability which would otherwise mitigate the risk of a significant supply interruption for these customers in the event of a zone substation transformer failure. Both transformers are 54 years old and testing has demonstrated extensive deterioration,⁵⁷ meaning both are at the end of their technical life and are at risk of catastrophic failure. Furthermore, customers' maximum demand⁵⁸ is forecast to exceed the zone substation's N-1 rating in 2022.

The installation of two new transformers (and maintaining one of the existing transformers as a hot-spare) is the most economic option to address the growing supply risk to customers in the Heidelberg area. This project formed part of our forecast capital expenditure for the current regulatory period. We commenced detailed design work for the replacement of both transformers in CY19. However, this work identified complexities associated with underground assets located inside the zone substation site. We will now need to undertake works within the site in multiple stages, meaning expenditure will be incurred later than initially forecast, including a small amount of expenditure in the first year of the next regulatory period. We expect one transformer to enter service prior to the next regulatory period and the second to enter service during the next regulatory period.

4.8.2 Distribution transformers

We largely replace distribution transformers to meet increasing capacity requirements (with this expenditure forming part of our augmentation program described in section 6), meaning relatively few distribution transformers are replaced due to them reaching the end of their technical lives. Where a transformer is replaced with a larger unit due to growing capacity requirements, we assess the condition of the unit removed to determine whether it would be efficient to refurbish it and return it to service elsewhere in the network when required.

As such, and in contrast to our approach for zone substation transformers, our replacement expenditure forecast for distribution transformers continues to be based on (reactive) replacement upon failure. We maintain a minimum stock level of transformers to ensure that any failed transformer can be replaced promptly to minimise customer outage duration. Alternative approaches such as undertaking age or condition-based replacement (rather than running these assets to failure) would likely result in the replacement of assets with some remaining useful life not utilised, despite the risks associated with in-service failure being low. Such an approach would provide a lower net benefit to customers over the long-term compared to our reactive replacement approach.

Our forecast expenditure to replace failed pole-mounted, ground-mounted and indoor transformers is based on an expectation of consistent asset failure rates in the future—resulting in a total of 258 to be replaced during the next regulatory period. We also propose to continue our current levels of activity replacing or refurbishing kiosks that house some transformers.

Following a risk assessment of each site, we have identified approximately 250 distribution transformers which are mounted too low on poles, or breaching exclusion zones required by the Electricity Safety (Installations) Regulations 2009. These low platforms pose a safety risk to the public as their no-go zones may more easily be encroached upon, and platforms mounted in road reserves are also at higher risk of being hit by passing trucks.

⁵⁷ Including DP values of 295 and 230 and very high moisture contents.

⁵⁸ At a 10 per cent probability of exceedance.

We propose to rectify the mounting height of 50 non-compliant transformer platforms over the next regulatory period, prioritising those which represent the highest risk.

4.8.3 References

Supporting documents included as part of our regulatory proposal or response to the Reset RIN for our forecast transformer replacement capital expenditure are listed below.

Document title	Location
Distribution Asset Class Strategy	RIN Response
Primary Plant Asset Class Strategy	RIN Response
Network Performance Plan	RIN Response
HB Transformer Replacement Business Case	RIN Response
Heidelberg (HB) Transformer Condition Risk Report	RIN Response
BD Transformer Replacement Business Case	RIN Response

4.9 Switchgear

Switches are used to control the flow of electricity on the network. In the event of a network fault, switches are used to isolate the location of the fault and minimise the number of customers who need to remain off supply, allowing the safe restoration of supply to others. Switchgear can be considered in two groups:

- zone substation switchgear—circuit breakers located within zone substations, at both the high voltage and sub-transmission levels
- distribution switchgear, located on lines throughout the network—includes automatic circuit reclosers, air break and gas-insulated load break switches, remote-controlled gas switches, isolators and LV outdoor switches.

Zone substation switchgear can fail due to high resistance connections, mechanical degradation, moisture ingress (for outdoor installation) or manufacturing faults. A typical zone substation has three 66 kV circuit breakers and between 8 and 12 distribution feeders, supplying up to 30,000 customers. The mechanical breakdown of a zone substation circuit breaker—and its resultant failure to operate—can, therefore, have significant customer supply consequences and pose serious safety public risks.

Distribution switchgear can fail due to factors including high resistance connections or components, insulation breakdown, degradation of mechanical components or auxiliary component failure (like communication or control systems for remote-controlled devices). The main consequence of distribution switchgear failure is a loss of supply to a higher (but still relatively small) number of customers in the event of a network fault, though can also pose a degree of safety risk. Distribution switchgear is, therefore, less critical than zone substation switchgear.

Figure 4–15 illustrates longer-term trends in our switchgear replacement expenditure. Our forecast expenditure is higher than during the current regulatory period, with this increase attributable to zone substation switchgear. During the current regulatory period, our zone substation replacement activities have focussed on transformers, with this having driven higher transformer replacement expenditure which will reduce during the next regulatory period (as discussed in section 4.8). As our zone substation transformer replacement needs lessen, our zone substation replacement focus is shifting to switchgear and other secondary equipment whose condition needs to be addressed. In the next regulatory period, we propose to undertake several major station rebuild projects which will involve significant switchgear expenditure (discussed further in section 4.9.1). Furthermore, our switchgear replacement expenditure during the current regulatory period has been suppressed as zone substation switchgear

which would otherwise have been replaced was augmented in response to localised demand growth, at zone substations such as Flemington, Sunbury and Preston. Our forecast expenditure on distribution switchgear is in line with expenditure during the current regulatory period.

Figure 4–15: Switchgear replacement expenditure (\$ June 2021, millions)

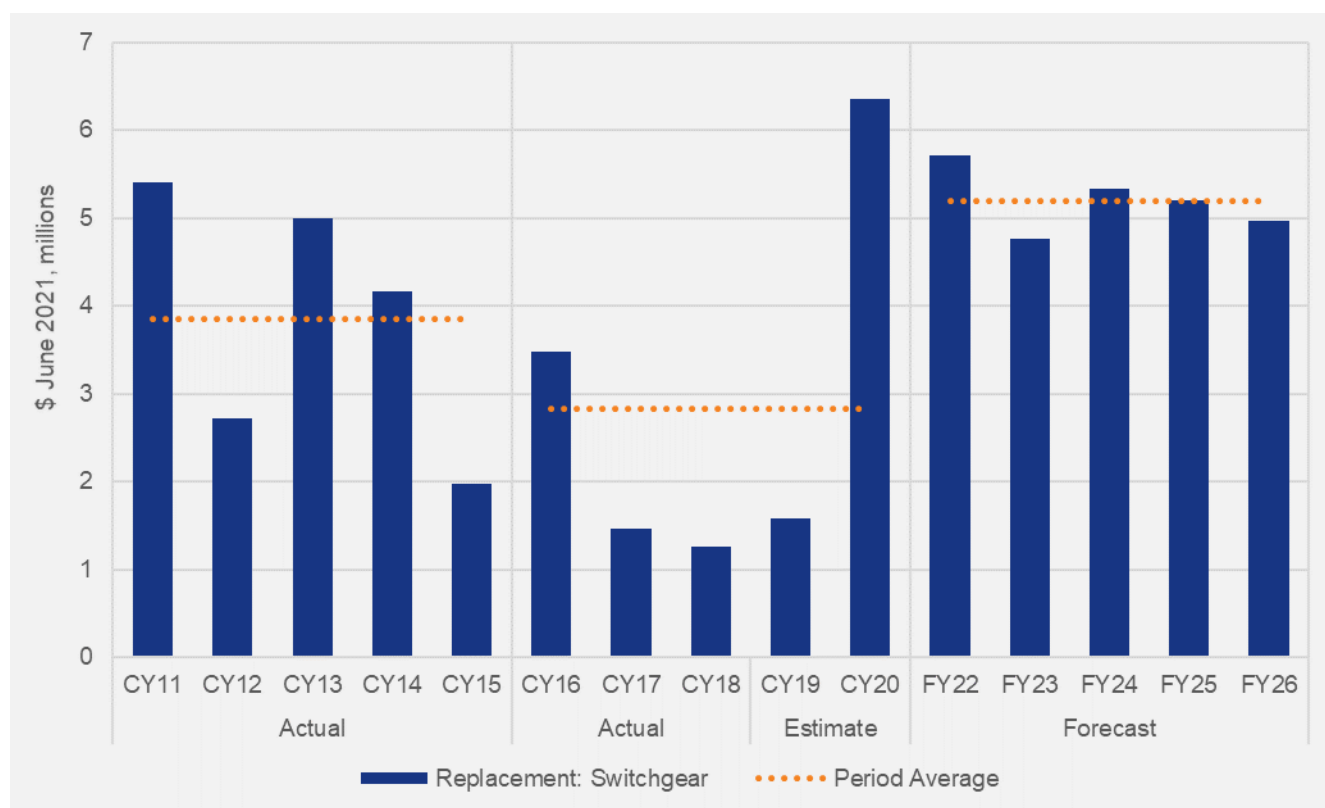


Table 4–8 sets out our forecast replacement expenditure for switchgear, and sections 4.9.1 and 4.9.2 discuss our forecast expenditure for zone substation and distribution switchgear respectively.

Table 4–8: Forecast replacement expenditure – switchgear (\$ June 2021, millions)

	FY22	FY23	FY24	FY25	FY26	Total
Zone substation switchgear	4.1	3.2	3.8	3.6	3.5	18.2
Distribution switchgear	1.6	1.6	1.6	1.6	1.5	7.8
Total	5.7	4.8	5.3	5.2	5.0	26.0

4.9.1 Zone substation switchgear

We propose to continue replacing zone substation switchgear once all cost-effective maintenance and life extension options have been exhausted and condition monitoring indicates a deteriorated condition and likely in-service failure, prioritising those with the highest risk.

For the forecast period, we propose to undertake major switchgear replacement programs at the Coburg North (CN) and Coburg South (CS) zone substations (in conjunction with projects to replace all protection and control systems at both zone substations). Together, these two projects will address serious safety risks and mitigate supply risks to over 40,000 customers by replacing old and deteriorated equipment with a history of failures and

which is non-compliant with current standards, maintenance-intensive or no longer supported by the manufacturer.

The risks identified at both CN and CS zone substations are similar, with both designed initially to similar standards and constructed at a similar time. Risks and issues identified at each zone substation, and our proposed works to address these needs, are set out in Table 4–9. For both CN and CS, alternatives such as doing nothing, maintenance and refurbishment were considered and shown not to address the significant safety and supply reliability risks identified. Additionally, in both cases, the option of load transfer to a new zone substation (alleviating the need to replace equipment at CN or CS) was shown to require a significantly higher expenditure than our proposed approach of replacing the degraded switchgear.

Table 4–9: CN and CS switchgear replacement

Site	Issues identified	Proposed works
CN	<ul style="list-style-type: none"> One 51-year-old 66 kV circuit breaker with a family history of mechanical and catastrophic bushing failures. Spare parts are not available and the manufacturer no longer supports the model. Circuit breaker controls operate at a different voltage to JEN standard. One 28-year-old oil-filled 66 kV circuit breaker is maintenance intensive, no longer supported by the manufacturer and spare parts are not available. Controls operate at non-standard voltage. One 51-year-old outdoor 22 kV circuit breaker is significantly degraded. JEN has experienced excessive wear, failures and high maintenance requirements with this model at other zone substations. The manufacturer no longer supports the model and spare parts are not available. All three outdoor 22 kV circuit breakers are non-compliant with current standards for electrical arc fault containment. 22 kV transfer bus has known defects, including pin and cap insulators prone to failure. 	<p>Replace existing 22 kV and 66 kV outdoor circuit breakers with modern equivalent indoor switchgear, installed to current standards, and the retirement of the outdoor 22 kV transfer buses.</p> <p>Works to be undertaken in CY22 and CY23.</p>
CS	<ul style="list-style-type: none"> One 52-year-old 66 kV circuit breaker with a family history of mechanical and catastrophic bushing failures. Spare parts are not available and the manufacturer no longer supports the model. Circuit breaker controls operate at a different voltage to JEN standard. 22 kV switchboard is obsolete, not supported by the manufacturer and spare parts that would be necessary to recover from a catastrophic failure are not available. Two indoor 22 kV buses and associated circuit breakers are 51 years old and have significantly deteriorated. Partial discharge has been detected on the 22 kV switchboard during routine testing, with intrusive inspection indicating irreversible insulation degradation that risks catastrophic failure. Oil leaks detected on circuit breakers which indicate risk of circuit breaker failure. Switchgear is non-compliant with current standards for electrical arc fault containment. 	<p>Replace two existing 22 kV buses and switchgear, and replace one 66 kV circuit breaker with modern equivalent equipment, installed to current standards.</p> <p>Works to be undertaken in CY23 and CY24.</p>

Our forecast also includes expenditure to complete the replacement of switchgear at both Footscray East (**FE**) and Footscray West (**FW**) zone substations, with both of these projects commencing during the current regulatory period. We had initially planned to undertake these works between CY18 and CY20. Both zone substations use the same makes and models of critical equipment (not used elsewhere on our network) which exhibit similar condition degradation issues and were expected to reach the end of their useful lives during the current regulatory period. Given the similarity of the equipment and condition issues at two zone substations located close to each other, we considered that it would be prudent to stagger these works (rather than undertake the projects

concurrently) to leverage learnings from the first project and maintain the security of supply to customers in the broader Footscray area.

During the current regulatory period, our assessment of the condition of the assets at both FE and FW indicated that it would be possible to delay replacement of these assets without significant detriment to safety and supply reliability. We, therefore, deferred the replacement of equipment at FE (originally due to commence in CY18) to begin in late CY19, and we now expect to complete works at FE early in the next regulatory period. As it remains prudent to stagger this program of works across FE and FW, and as our inspection activities continue to indicate that the health of the assets at FE is lower than at FW, we therefore also deferred the replacement of relays and switchgear at FW, and we now expect to complete those works in FY22.

4.9.2 Distribution switchgear

As the consequences of a failure of distribution switchgear are relatively low, we will continue to employ a predominately replace-on-failure approach for most overhead switchgear, though replacement may also be undertaken if a need is identified through inspection when a network operator uses the equipment. Our forecast expenditure for the replacement of failed or significantly deteriorated gas switches, indoor or kiosk switchgear and LV switchgear is therefore based on our expectation of consistent asset failure rates into the future.

A smaller part of our program also includes the replacement of particular manufacturer types or models of switchgear which have now been identified as at higher risk of failure and which pose a safety risk, to avoid this equipment failing while in service. We also propose to commence new a routine replacement program to address a small number of deteriorated automatic circuit reclosers (**ACR**), a type of device first installed in the 1990s. This program will aim to address declining insulating gas pressure in this equipment (identified through our inspection and remote asset monitoring programs), with replacement once pressure falls below a certain level being the most effective means of addressing this issue.

4.9.3 References

Supporting documents included as part of our regulatory proposal or response to the Reset RIN for our forecast switchgear replacement capital expenditure are listed below.

Document title	Location
Distribution Asset Class Strategy	RIN Response
Primary Plant Asset Class Strategy	RIN Response
Network Performance Plan	RIN Response
FW Zone Substation Switchgear and Relay Condition Risk- Draft Project Assessment Report	RIN Response
Footscray East (FE) Switchgear Condition Risk Report	RIN Response
FE Switchgear Replacement Business Case	RIN Response
CS Switchgear Replacement Business Case	RIN Response
CN Switchgear Replacement Business Case	RIN Response

4.10 SCADA, network control & protection systems

This replacement expenditure category⁵⁹ can be further disaggregated into the following sub-categories, each of which is discussed in the sections below:

- protection systems

⁵⁹ Consistent with the category definitions in the Reset RIN, all SCADA, network control & protection system equipment is located on the network side of gateway devices (routers, bridges etc.) at corporate office sites.

- communications infrastructure
- other.

Figure 4–16 illustrates longer-term trends in our SCADA, network control and protection systems expenditure, and shows a material increase in expenditure during the next regulatory period. The predominate driver of this increase during the next regulatory period is our expenditure on protection systems. Similarly to the trends in our switchgear expenditure discussed in section 4.9, our zone substation replacement focus is shifting from transformer replacement to switchgear and secondary replacement. We are proposing to undertake several station rebuild projects during the next regulatory period which will involve significant expenditure on relay replacement, including Coburg North, Coburg South and Footscray West. Our forecast expenditure on communications infrastructure and other equipment within this category is in line with our expenditure during the current regulatory period.

Figure 4–16: SCADA, network control & protection systems replacement expenditure (\$ June 2021, millions)

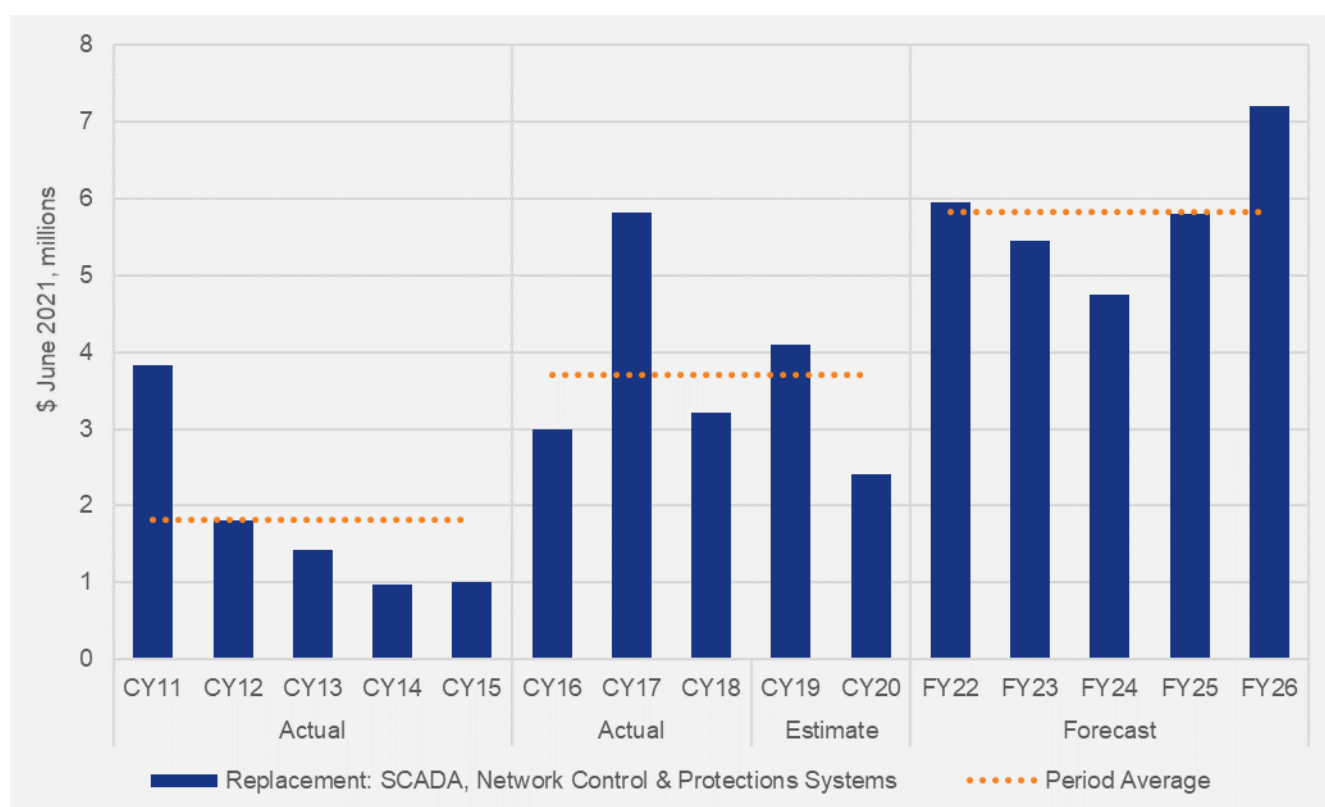


Table 4–10 sets out our forecast expenditure on the three sub-components of this expenditure category, each of which are discussed in the sections below.

Table 4–10: Forecast replacement expenditure – SCADA, network control & protection systems (\$ June 2021, millions)

	FY22	FY23	FY24	FY25	FY26	Total
Protection systems	4.1	4.3	4.0	4.7	6.1	23.2
Communications infrastructure	0.9	1.2	0.8	0.8	0.8	4.5
Other	0.9	0.0	0.0	0.3	0.3	1.5
Total	5.9	5.4	4.7	5.8	7.2	29.1

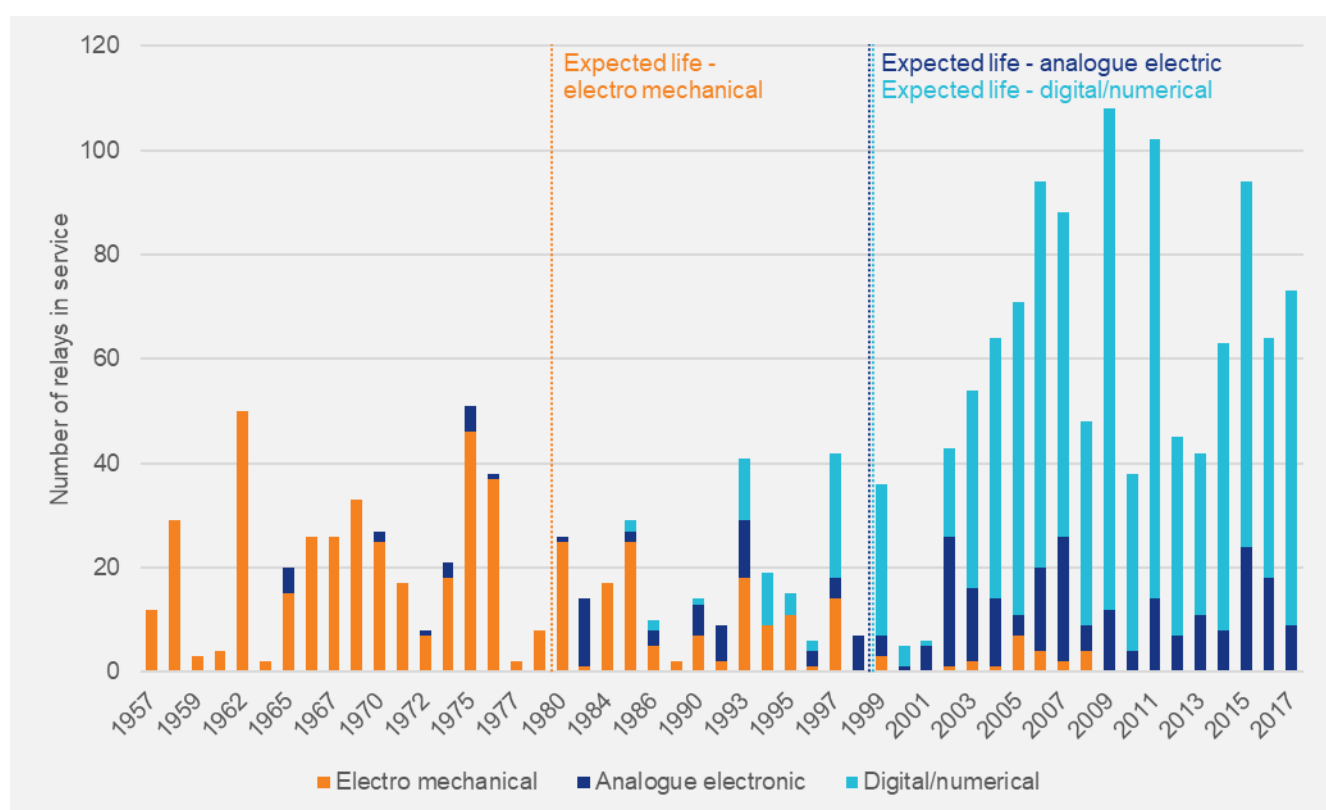
4.10.1 Protection systems

This sub-category covers zone substation protection and control systems, including relays and power supplies. Our condition-based replacement of protection and control schemes represents the most significant portion of expenditure within the SCADA, network control and protection systems replacement category. The protection and control schemes within our zone substations are considered critical systems within our network. A correctly functioning scheme ensures the safe and reliable operation of our sub-transmission system and our HV network. The purpose of these assets is to rapidly detect faults in the network and send signals to switchgear to isolate those faults. This action minimises the impact of a fault on customer supply and ensures dangerous fault currents do not result in safety hazards or damage to equipment. The failure of a relay to operate when required to do so, therefore, represents a significant safety risk to our staff and members of the public.

It is not possible (or cost-effective) to altogether remove the possibility of all failures of this equipment. However, we aim to replace our protection schemes when they exhibit unreliable behaviour, with risks suggesting that it would no longer be prudent and efficient to continue their use. We, therefore, monitor the performance of relay types and models to identify emerging failure trends. Modern secondary equipment employs comprehensive self-monitoring functions and diagnostic features. These relays are capable of reporting back to JEN's co-ordination centre via SCADA when they are faulty. However, older electro-mechanical models of relays have neither remote monitoring features nor status indicators on them, meaning that we are only able to know with certainty that they are at the end of their technical lives after they have failed to operate as required. Given the significant safety consequences of this, we must as best as possible estimate the condition of this equipment and aim to replace it before it reaches the end of its life.

Historically, we have expected a technical life of 40 years for electro-mechanical relays. Although the manufacturer's estimates of life expectancy have been open-ended subject to regular preventative maintenance being performed, condition degradation is occurring. Our electro-mechanical relay populations are now very old, with 74 per cent of these relays over their expected life of 40 years, and are showing signs of end of life deterioration. The age profile of our relay population by type is illustrated in Figure 4–17. Recent maintenance on these relays has shown significant timing errors which indicate a weakening in strength of the braking magnet—this could cause the equipment to not operate in accordance with the design of the protection system and result in the backup protection system being relied upon, causing a larger supply interruption. While we have been able to rectify these timing errors through maintenance, most electro-mechanical relays have a limited range of mechanical adjustment and once that limit is reached it is not possible to keep the relay in service.

Figure 4–17: Age profile and expected lives of relays by type



Spare parts for some types of electro mechanical and earlier analogue electronic relays are increasingly scarce as manufacturers cease support for these old models. Maintaining the availability of spare parts is critical to allowing for any unplanned maintenance or repairs necessary to keep these models in service, as old models of relay are generally not compatible with modern relays. The replacement of a failed relay with a different model could require complex and lengthy works to redesign the protection scheme or build customised interfaces, representing a potentially significant disruption to customer supply. A lack of availability of spare parts is therefore increasingly driving the planned replacement of relays.

We are also planning to target two types of early model digital relays with known faults for replacement. These ABB and GE relays are experiencing ongoing failures due to manufacturer design weaknesses in their power supply modules, making replacement the only technically viable solution in the long-term for these models.

Our forecast expenditure for the next regulatory period includes the replacement of protection relays as set out in Table 4–11.

Table 4–11: Proposed protection system replacement projects, FY22-26

Site	Number of replacement relays to be installed	Project completion (FY)	Notes
Coburg North zone substation	57	FY24	Full new secondary as part of a station rebuild. Majority of relays to be replaced are old electro-mechanical type.
Coburg South zone substation	34	FY26	Full new secondary as part of a station rebuild. Majority of relays to be replaced are old electro-mechanical type.

Site	Number of replacement relays to be installed	Project completion (FY)	Notes
Footscray West zone substation	61	FY22	Full new secondary as part of a station rebuild. Majority of relays to be replaced are old electro-mechanical type. Commences prior to the start of the next regulatory period.
North Essendon zone substation	31	FY26	Will address known equipment defects in early digital/numerical relays.
Braybrook zone substation	15	FY22	Will address known equipment defects in early digital/numerical relays. Commences prior to the start of the next regulatory period.
North Heidelberg zone substation	26	FY26	Will address known equipment defects in early digital/numerical relays.

Each of these projects is designed to reduce the risk of poor operation and performance of deteriorated relays and protect against degradation in network safety and performance. Additionally, these projects will address the physical space limitations and health and safety risks associated with some of the control buildings which house this equipment.

Timing for three of these projects is planned to achieve delivery efficiencies by replacing relays in conjunction with the replacement of other equipment within the zone substation. As noted above, the Coburg North, Coburg South and Footscray West relays will be replaced concurrently with the replacement of other secondary equipment and switchgear at those zone substations (refer to section 4.9.1). There are several equipment performance and degradation issues at each of these stations, and our forecast expenditure reflects the most prudent and efficient option of rebuilding all equipment within the same delivery project.

4.10.2 Communications infrastructure

This sub-category includes equipment deployed throughout our network which provides connectivity between network devices and zone substations, our SCADA system and our control room. The visibility, monitoring, operation and control of our network—and therefore the reliability of supply to customers—is dependent upon these assets performing as required.

Specific assets within this category include communications network devices, remote terminal units, multiplexer systems, iNet radio and 3G service equipment⁶⁰ and communications cables. Consistent with the definitions contained in the Reset RIN, SCADA and network control assets located on the corporate office side of gateway devices are classified as non-network IT and communications and are covered in section 7.2.

Our focus for the next regulatory period is to continue replacing end-of-life network communications equipment to ensure network performance is not negatively impacted, in addition to strengthening security management of field communications devices, in response to growing threats of cyber-attacks and physical security breaches—consistent with our heightened focus on the cybersecurity of non-network IT and communication assets outlined in section 7.2.3.1.

4.10.3 Other SCADA, network control & protection system assets

This sub-category covers measurement equipment used for operational purposes throughout the network, mostly relating to power quality metering but also including wholesale market meters and asset wear monitoring equipment. Our forecast consists of a small amount of expenditure required to replace equipment which has

⁶⁰ We plan to upgrade existing 3G equipment to 4G during the next regulatory period, in line with the planned shut-down of 3G networks by telecommunication providers.

reached the end of its technical life or is otherwise exhibiting performance issues which would prevent it from accurately recording or monitoring network performance and faults.

4.10.4 References

Supporting documents included as part of our regulatory proposal or response to the Reset RIN for our forecast SCADA replacement capital expenditure are listed below.

Document title	Location
JEN SCADA & RTS Asset Class Strategy	RIN Response
Secondary Plant Asset Class Strategy	RIN Response
Measurement Asset Class Strategy	RIN Response
FW Zone Substation Switchgear and Relay Condition Risk- Draft Project Assessment Report	RIN Response
CS Relay Replacement Business Case	RIN Response
CN Relay Replacement Business Case	RIN Response
NH/NEI Relay Replacement Business Case	RIN Response
NS Relay Replacement Business Case	RIN Response
BY Relay Replacement Business Case	RIN Response
ZSS Batteries & Chargers Replacements 2021-2025 Business Case	RIN Response
End of Feeder Power Quality Meter Replacement Business Case	RIN Response

4.11 Other

This category includes all other asset replacement expenditure, and consists of:

- customer-initiated asset relocation works
- emergency recoverable works
- other assets.

Each of these three areas is discussed in the sections below, and our forecast capital expenditure for the other category is set out in Table 4–12.

Table 4–12: Forecast replacement expenditure – other (\$ June 2021, millions)

	FY22	FY23	FY24	FY25	FY26	Total
Customer-initiated asset relocations	6.9	6.9	7.3	7.6	8.0	36.7
Emergency recoverable works	2.3	2.3	2.4	2.4	2.4	11.8
Other assets	1.4	2.6	1.3	0.9	1.0	7.2
Gross capital expenditure	10.6	11.9	11.0	10.9	11.4	55.7
Capital contributions	6.7	6.8	7.1	7.4	7.7	35.6
Net capital expenditure	3.8	5.1	3.9	3.5	3.7	20.1

4.11.1 Customer-initiated asset relocations

This expenditure relates to works we must undertake⁶¹ at the request of customers, councils, government authorities and other third parties to relocate or otherwise rearrange our assets, generally to allow for works to be undertaken on other infrastructure, such as road construction.

We have developed our forecast consistent with the service classification set out in the AER's final Framework & Approach for the next regulatory period⁶² and in accordance with the requirements of the Essential Services Commission's Electricity Industry Guideline 14.⁶³ As such, while significant in gross terms, this capital expenditure is almost entirely funded up-front by the party requesting the works, and therefore has no material impact on our regulatory asset base or the prices paid by other customers.

Similarly to connections expenditure, this expenditure is wholly driven by customer requests, with levels of activity related to the volume of infrastructure construction activity occurring in our network area. To forecast this gross expenditure, we adopt the same top-down approach as we do for general connections expenditure, as described in section 5.2. This methodology involves taking an average of our annual asset relocations expenditure over the calendar years 2016 to 2018 and trending this annual expenditure forward to reflect changes in forecast growth (both positive and negative) in infrastructure construction activity in Victoria. We derive forecast growth rates in infrastructure construction activity using the Australian Construction Industry Forum's (ACIF) forecasts of activity in the road engineering and bridge, railway and harbour engineering segments.

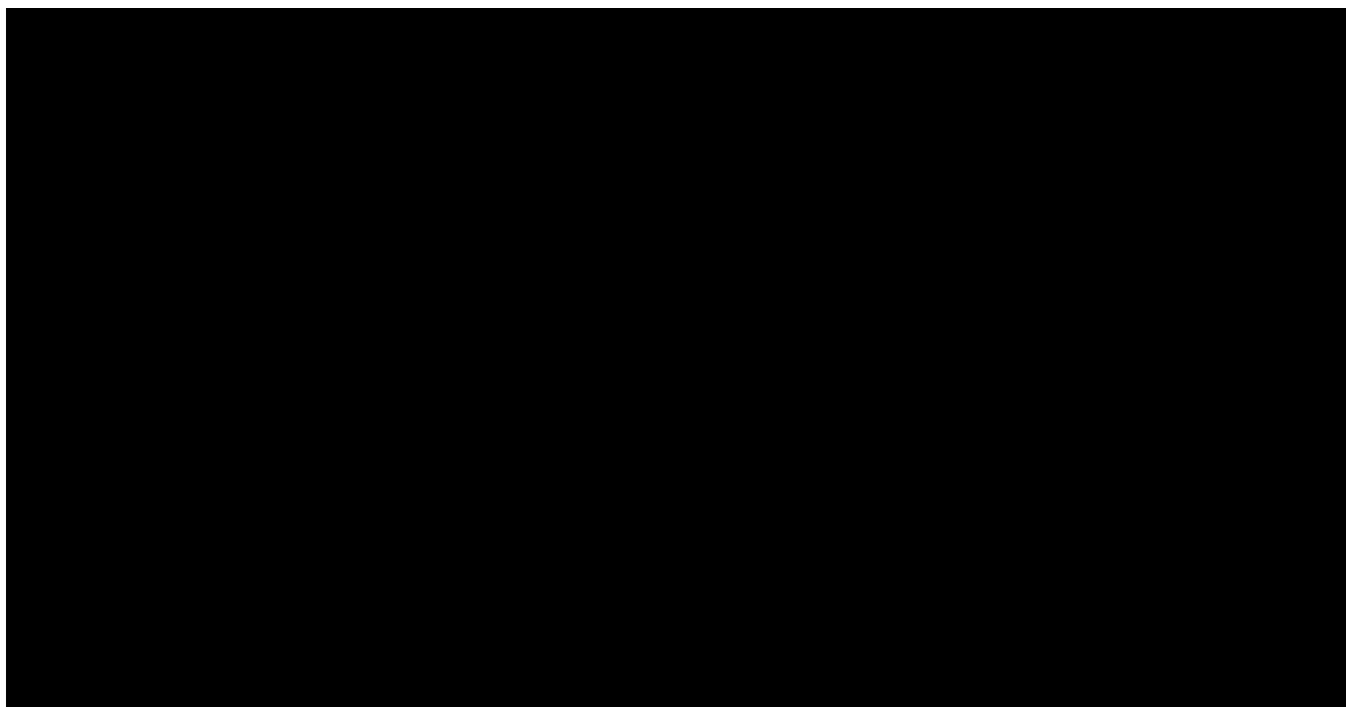
Throughout the next regulatory period, we expect the historically high levels of demand from customers for asset relocation activities seen in recent years to continue. This is due to several transport infrastructure projects under the Victorian Government's Big Build program, in addition to the ongoing Level Crossing Removal Program, Melbourne Airport rail link construction and North East Link construction. These high activity levels are reflected in the ACIF forecast for Victoria, illustrated in Figure 4–18. Although *growth* in forecast activity is forecast to slow in the early part of our next regulatory period, ACIF's forecast shows the current high levels of activity persisting throughout this time.

⁶¹ Consistent with the requirements of our Electricity Distribution Licence.

⁶² AER, *Final framework and approach – AusNet Service, CitiPower, Jemena, Powercor and United Energy, regulatory control period commencing 1 January 2021*, January 2019, p. 99. 'Third party initiated asset relocations/re-arrangements under ESCV Guideline 14' is listed under common distribution services as a SCS.

⁶³ This includes recognition of any avoided costs for other customers which may result from the requested works.

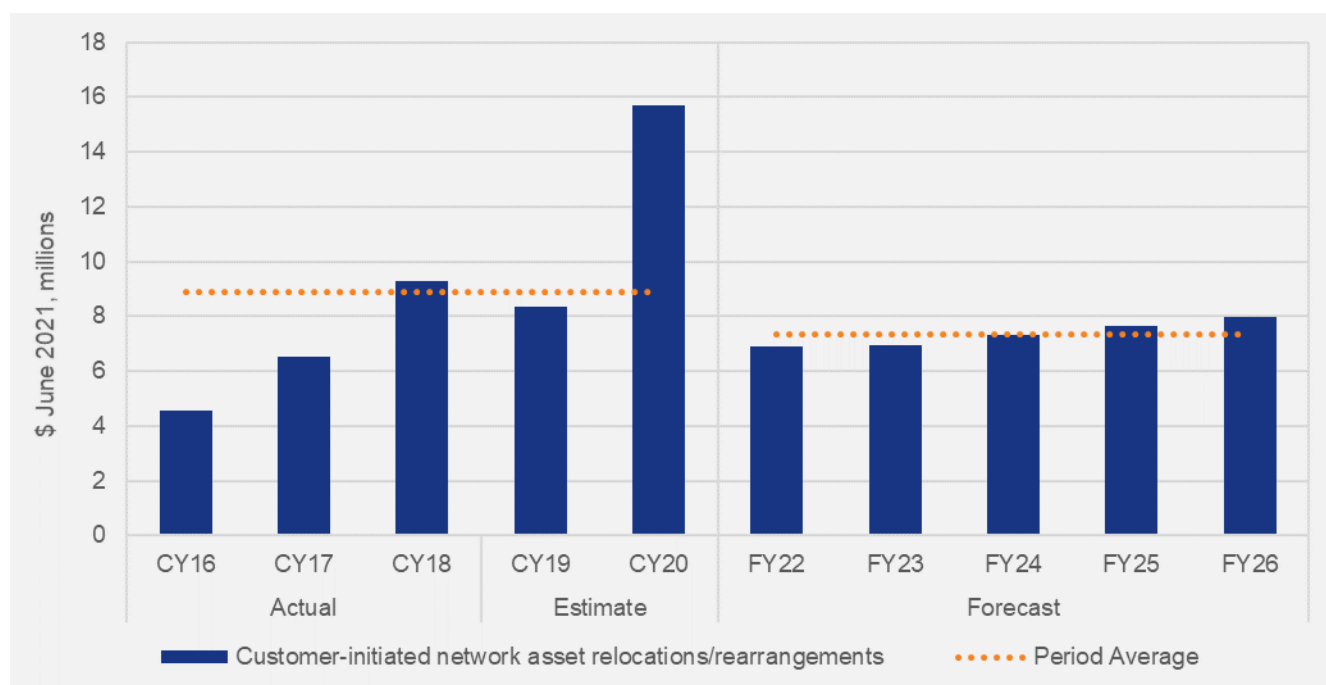
Figure 4–18: Value of infrastructure construction activity in Victoria



Source: Australian Construction Industry Forum, Australian Construction Market Report, May 2019.

Trends in our asset relocation expenditure are shown in Figure 4–19.

Figure 4–19: Customer-initiated asset relocation expenditure (\$ June 2021, millions, gross)



- (1) Information for the 2011-15 regulatory period is not shown, as JEN did not report asset relocation expenditure within the replacement expenditure category in its annual responses to the Category Analysis RIN before CY16.

4.11.2 Emergency recoverable works

This category of expenditure relates to work to make the network safe and maintain supply to customers by repairing damage to our distribution network following an identifiable third party's act or omission, for which that party is liable. This includes damage to poles caused by motor vehicle accidents, damage to underground cables caused by unauthorised excavation works or damage to overhead lines caused by high vehicles. The activities required to rectify such damage can vary widely, but often involve the replacement of assets such as poles after they have been damaged.

The AER's final Framework & Approach for the next regulatory period classifies activities relating to emergency recoverable works as standard control services,⁶⁴ which represents a change from the classification of this service (from an unclassified service) during the current regulatory period. We have accounted for this service classification change when developing our forecast as described below. As noted in by the AER in the Framework & Approach, we remain incentivised to maximise the recoveries we receive from liable third parties, given the continued application of the Capital Efficiency Sharing Scheme.

To develop our forecast emergency recoverable works expenditure, we:

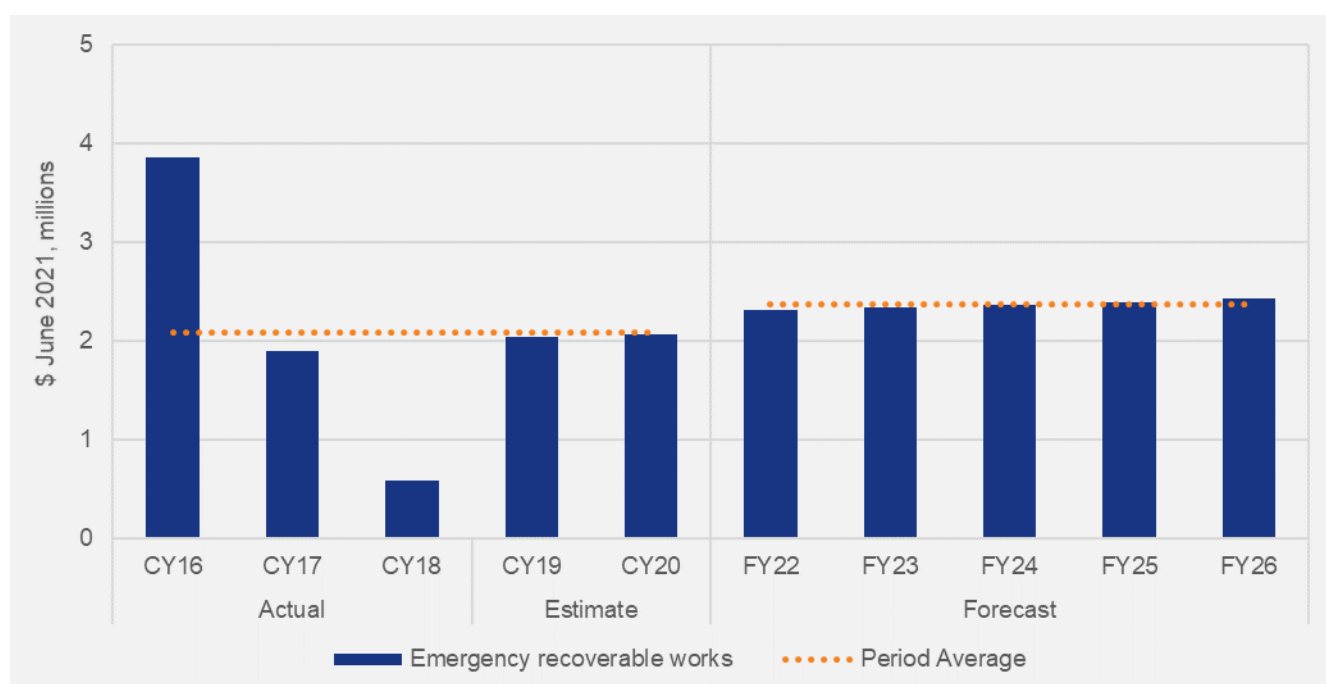
- took an average of our actual direct costs of rectifying damage over calendar years 2017 and 2018
- reduced these costs by the average amount successfully recovered from liable third parties who caused this damage—resulting in a 'net' amount of emergency recoverable works expenditure under the proposed service classification for the next regulatory period⁶⁵
- applied a scale escalator—reflecting forecast growth in our network's circuit length—to our emergency recoverable works annual net expenditure, to account for expected annual increases in the value of damage and associated recoveries.

Figure 4–20 shows our longer-term trends in our emergency recoverable works expenditure.

⁶⁴ AER, *Final framework and approach – AusNet Service, CitiPower, Jemena, Powercor and United Energy, regulatory control period commencing 1 January 2021*, January 2019, p. 98.

⁶⁵ This adjustment to our 'base' years of expenditure ensures we have accounted for the difference in regulatory cost recovery treatment between the current and new classifications. Under the new classification, amounts which we are unsuccessful from recovering from a liable third party (for example, where the party defaults or is unable to pay) will be included in our regulatory asset base.

Figure 4–20: Emergency recoverable works expenditure (\$ June 2021, millions)



(1) Data for the 2011-15 regulatory period is not available as emergency recoverable works were classified as a quoted service during this time.

4.11.3 Other assets

There are some other types of assets which are not covered by any of the AER's preferred replacement expenditure categories, which are discussed below.

Substation housings, buildings and grounds

Our plan includes expenditure to continue refurbishing and, where necessary, replacing structures which form part of zone substations or distribution substations, such as control buildings to protect indoor equipment such as switchgear. It also includes replacing security equipment such as fences, CCTV and security lighting necessary to ensure these sites can continue to operate safely and securely. Although this expenditure is relatively small, we are putting a stronger focus on investing to improve physical site security measures in response to incidents of trespassing and theft and the need to protect critical infrastructure. This sub-category does not include expenditure for buildings located on non-network sites, such as offices.

Earthing systems

Earthing systems are installed with distribution and zone substations to reduce the risk of electrical shock to people or property damage under abnormal supply conditions. They are susceptible to corrosion or mechanical fatigue or damage which can compromise their performance, posing a serious safety risk in some circumstances. We propose to continue replacing or refurbishing earthing systems when periodic inspection (mandated under Victoria's *Electricity Safety (Network Assets) Regulations 1999*) and testing reveals degradation and the potential for the system to not perform to specified levels.

Capacitor banks

Capacitor banks are located inside zone substations and are used to raise network voltage, improving network capacity and reducing voltage drops at times of peak demand, reducing the risk of customer equipment failure

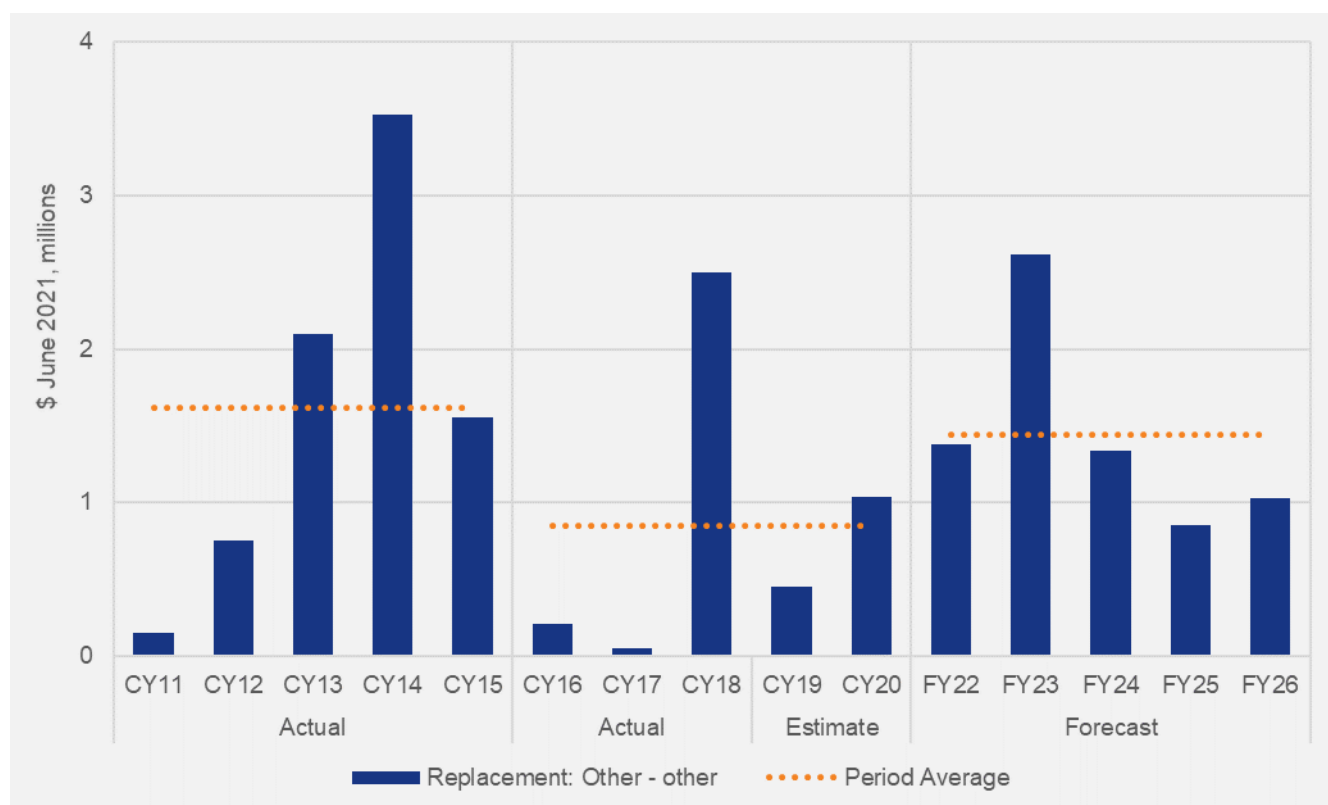
('brown-outs'). Our forecast includes a small amount of expenditure required to replace equipment which has failed or which is now technically obsolete and spares no longer available.

Surge diverters

Surge diverters are used to protect network and customer equipment from failure due to high fault currents (such as from lightning strikes). Our forecast includes a small amount of expenditure to replace failed equipment.

Figure 4–21 shows our longer-term expenditure trends in this category.

Figure 4–21: Other replacement expenditure (\$ June 2021, millions)



4.11.4 References

Supporting documents included as part of our regulatory proposal or response to the Reset RIN for our forecast other replacement capital expenditure are listed below.

Document title	Location
Customer Connections Forecast Methodology	RIN Response
Primary Plant Asset Class Strategy	RIN Response
Distribution Asset Class Strategy	RIN Response

5. Connections expenditure

5.1 Summary

Connections expenditure relates to connecting new customers to our network and augmenting or altering existing network connections.

Our connections expenditure objectives:

- Connect new customers to our network and meet the changing energy needs of existing customers, ensuring we can meet or manage expected demand for all customers at the least cost over the long-term

Our capital expenditure forecast for the next regulatory period comprises \$218M of gross connections expenditure, which includes capital contributions of \$117M. This represents a 13 per cent increase in gross connections expenditure from the current regulatory period.

Our connections expenditure is driven by our customers' requests to connect to our network, or to expand or reconfigure the connection assets used to supply them. Various regulatory instruments, including our Electricity Distribution Licence, oblige us to offer connection services to customers (including embedded generators) as well as to offer services such as undergrounding. The level of requests for connection services by customers is generally correlated with economic activity. Over the forecast period, we expect to continue to see growth in the number of customers we need to connect.

JEN presents its connections expenditure forecast using two categories, which reflect differences in the nature of the projects and our forecasting approaches:

- **general connections**—the vast majority of connections are in this category, with expenditure forecast using a top-down methodology
- **major customer connection projects**—large, specific 'one-off' projects which customers have advised JEN about, with expenditure forecast using a bottom-up methodology.⁶⁶

Overall, JEN's forecast of general connections expenditure is in line with longer-term trends in the growth of our customer base. Given the highly specific and customer-driven nature of major connections projects, trends in this sub-category of expenditure are less meaningful to analyse. Our forecast of major customer connections expenditure reflects our best available information about our customers' planned projects and includes several major commercial, residential development and infrastructure projects in JEN's network area.

Our connections expenditure forecasts in this section are presented on two different bases—gross and net. In line with our Connections Policy⁶⁷ and jurisdictional requirements,⁶⁸ we require customers to pay an upfront capital contribution to connection works where the cost of those works (referred to in aggregate as our **gross capital expenditure**) exceeds the incremental revenue forecast to be received from that connection. This ensures that existing customers of the network are not disadvantaged by new customers connecting. Where a capital contribution is payable, only the gross capital expenditure less the capital contribution is rolled into our regulatory asset base—this amount is referred to as **net capital expenditure**. Our forecasting methodology for capital contributions is explained in Appendix C.

Customers also make requests to relocate, modify or otherwise rearrange assets which form part of JEN's network, but which are not connections assets. Although such expenditure is fully customer-driven and outside JEN's control, we have not included this expenditure within the connections category and have instead included

⁶⁶ We define major customer connection projects as those where the customer's maximum demand exceeds 10 MW.

⁶⁷ Provided as Attachment 05-09.

⁶⁸ In particular, the Essential Services Commission of Victoria's *Electricity Industry Guideline No. 14*.

this within replacement expenditure (refer to section 4.11.1). Capital contributions are also applicable to asset relocation works. However, the contribution figures presented in this section relate to connections only.

Figure 5–1 shows our historical and forecast net connections capital expenditure and capital contributions. Our connections expenditure forecast is set out by connections expenditure type in Table 5–1 and by connections subcategory in Table 5–2.

Figure 5–1: Connections expenditure (\$ June 2021, millions)

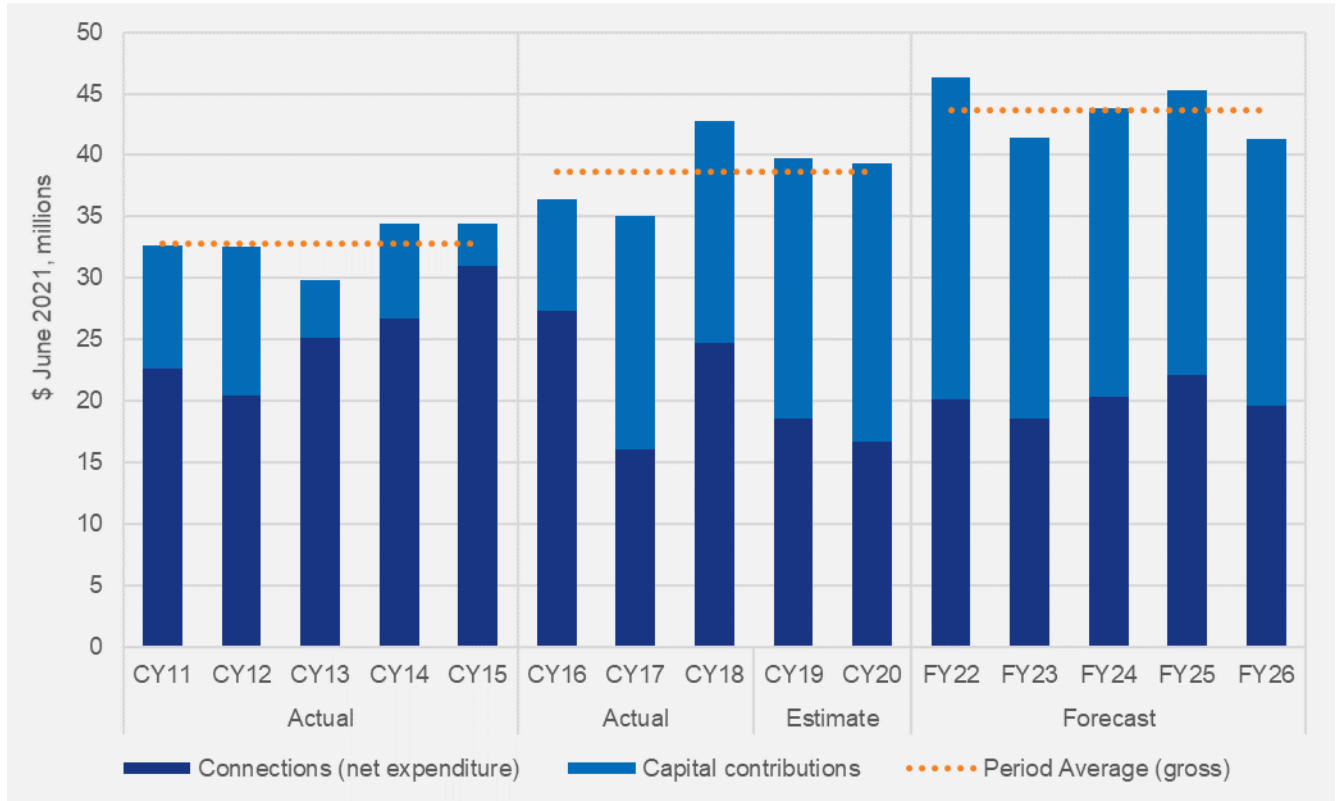


Table 5–1: Forecast connections expenditure by type (\$ June 2021, millions)

Connections expenditure type	FY22	FY23	FY24	FY25	FY26	Total
General connections ²	35.4	35.2	36.1	37.0	37.2	181.0
Major customer connection projects ²	10.8	6.3	7.6	8.2	4.2	37.1
Gross connections expenditure	46.3	41.4	43.8	45.2	41.3	218.0
Capital contributions ³	26.2	22.9	23.5	23.1	21.7	117.4
Net connections expenditure	20.1	18.6	20.3	22.1	19.6	100.7

(1) Standard control services only.

(2) Gross capital expenditure.

(3) Does not include capital contributions for asset relocation works, which are replacement expenditure – refer to section 4.11.1.

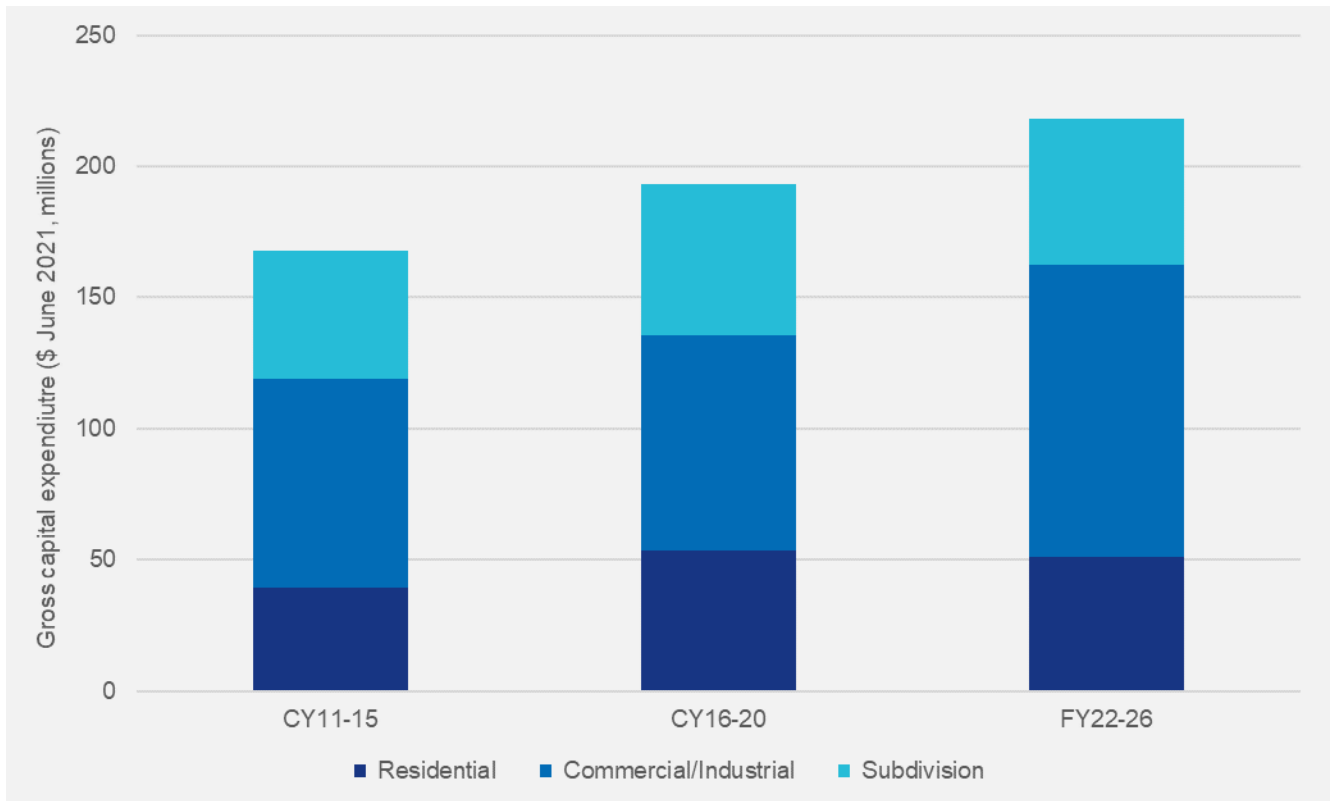
Our gross connections capital expenditure is shown in Table 5–1 and Figure 5–2 by connection subcategory, per the AER's RIN requirements.

Table 5–2: Forecast connections expenditure by connection subcategory (\$ June 2021, millions)

Customer category	FY22	FY23	FY24	FY25	FY26	Total
Residential	10.3	10.0	10.2	10.4	10.2	51.2
Commercial/industrial	24.7	20.5	22.4	23.5	19.9	111.0
Subdivision	11.2	10.9	11.1	11.4	11.2	55.8
Embedded generation	0.0	0.0	0.0	0.0	0.0	0.0
Total gross connections expenditure	46.3	41.4	43.8	45.2	41.3	218.0
Capital contributions ²	26.2	22.9	23.5	23.1	21.7	117.4
Net connections expenditure	20.1	18.6	20.3	22.1	19.6	100.7

(1) Standard control services only.

(2) Does not include capital contributions for asset relocation works, which are replacement expenditure – refer to section 4.11.1.

Figure 5–2: Historical and forecast gross capital expenditure by connection subcategory (\$ June 2021, millions)

The sections below provide information about JEN's general connections and major customer connection projects expenditure forecasts.

5.2 General connections

This category makes up the majority of our gross connections capital expenditure. It includes expenditure for making new connections or altering existing connections for all but the very largest of our customers. However, it does not include expenditure for connection services classified as Alternative Control Services.⁶⁹

⁶⁹ Such as the basic connection service typically applicable to a new residential connection.

Given that our expenditure within this category is entirely dependent on future customer requirements and that the future requirements of individual customers are for this category of connection are unknown ahead of time,⁷⁰ we develop our forecast expenditure on a top-down basis. This involves:

- adjusting our revealed capital expenditure for the 2016 to 2018 calendar years⁷¹ by customer type to remove expenditure relating to major customer connections projects
- taking an average of the three years of adjusted expenditure by customer type
- trending forward this 'base' expenditure by customer type using:
 - forecast growth in residential customer numbers for residential customer and subdivision connections
 - forecast growth in building and construction activity for various non-residential sectors in Victoria for commercial and industrial connections.

Below we discuss our new connections forecasts and the associated capital expenditure for the next regulatory period.

5.2.1 Connection activity levels

5.2.1.1 Residential customers

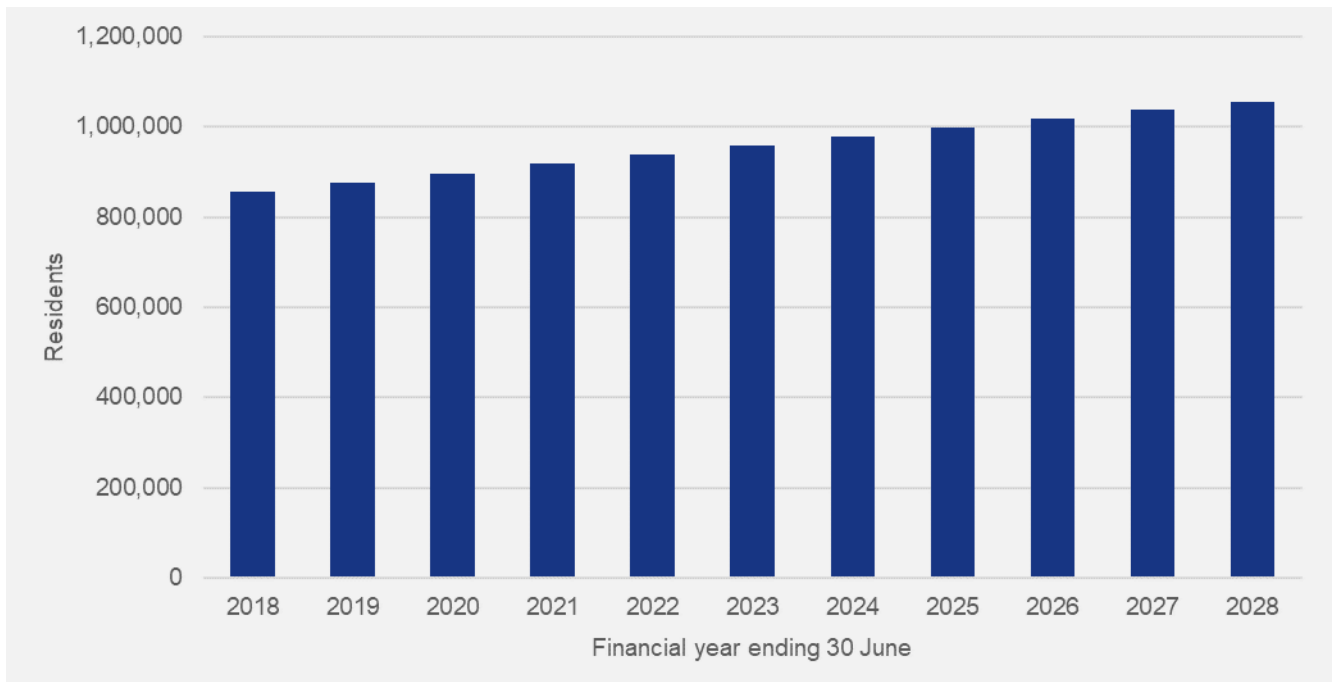
Our number of new customers is a crucial driver of our gross connections capital expenditure for general connections. We engaged independent experts ACIL Allen Consulting to develop forecasts of our customer numbers for the financial years 2019 to 2028.⁷² The number of customers supplied by our network has grown steadily over time, with average growth of 1.6 per cent per annum between June 2009 and June 2018. Population growth is a key driver of residential customer numbers, which represent approximately 90 per cent of our customer base. ACIL Allen Consulting's report presents projections of population growth by Local Government Area (LGA) within JEN's network area, based on projections from the Department of Environment, Land, Water and Planning's Victoria in Future 2016 report and the 2018-19 Victorian State Budget. These population projections by LGA are then weighted according to the number of households within each LGA that are supplied by JEN (as we supply all households within some LGAs but only a small number of households within others).

ACIL Allen Consulting's projection of the population residing in JEN's network area from June 2018 to June 2028 is presented in Figure 5–3. In the next regulatory period, the population of JEN's network area is forecast to increase from 918,000 to 1,018,900 people, which represents an average growth rate of 2.1 per cent per annum. Based on this, we expect to see relatively strong growth in residential customer connection activity continue during the next regulatory period. The rate of population growth is higher in the short-to medium-term, reflecting strong population influx to Victoria in recent years.

⁷⁰ Specific major customer projects which are known ahead of time are covered in section 5.3.

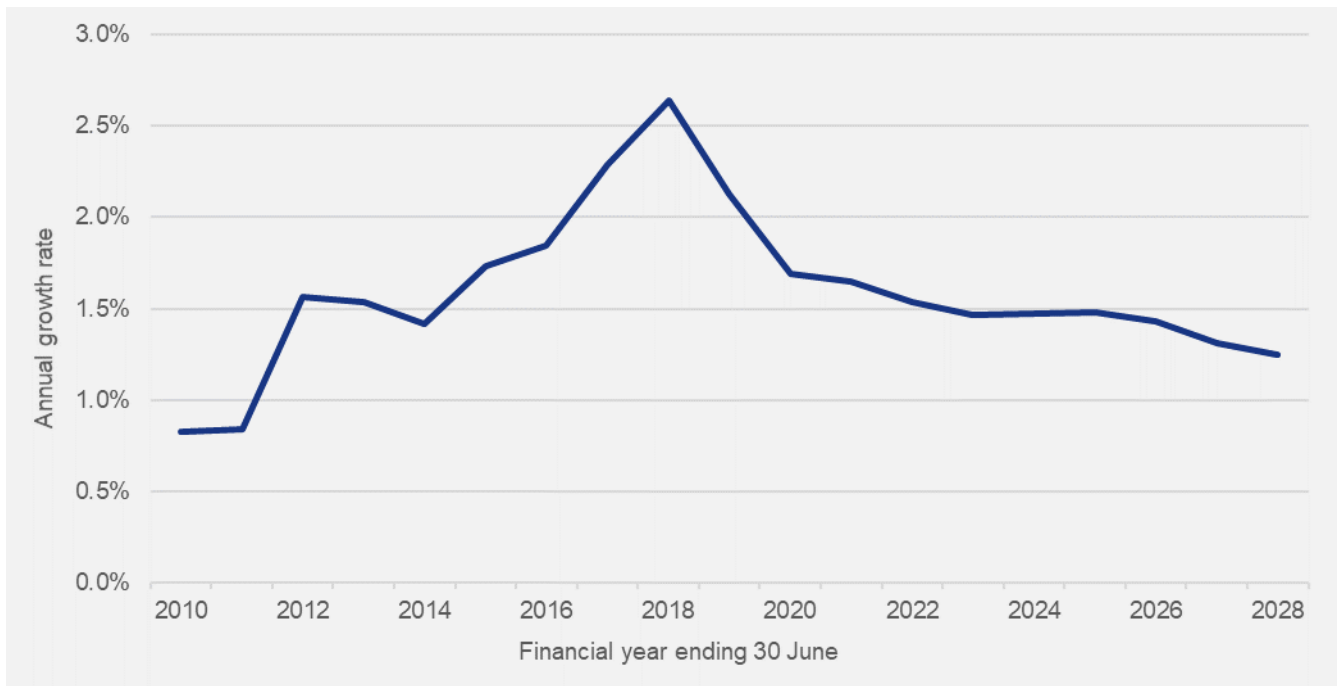
⁷¹ These are the three most recent years of audited connections capital expenditure. The classification of connection services reflected in these years is consistent with the classification set out in the AER's final Framework & Approach for the next regulatory period.

⁷² ACIL Allen Consulting's forecast report is provided as Attachment 05-03.

Figure 5–3: Projected population growth in JEN's network area

Source: ACIL Allen Consulting, JEN Demand Forecasts 2019-2028

ACIL Allen Consulting's forecast of JEN's residential customer annual growth rate is presented in Figure 5–4. While this shows the forecast growth slowing from its peak in 2018, growth remains positive throughout the next regulatory period, averaging around 1.5 per cent each year.

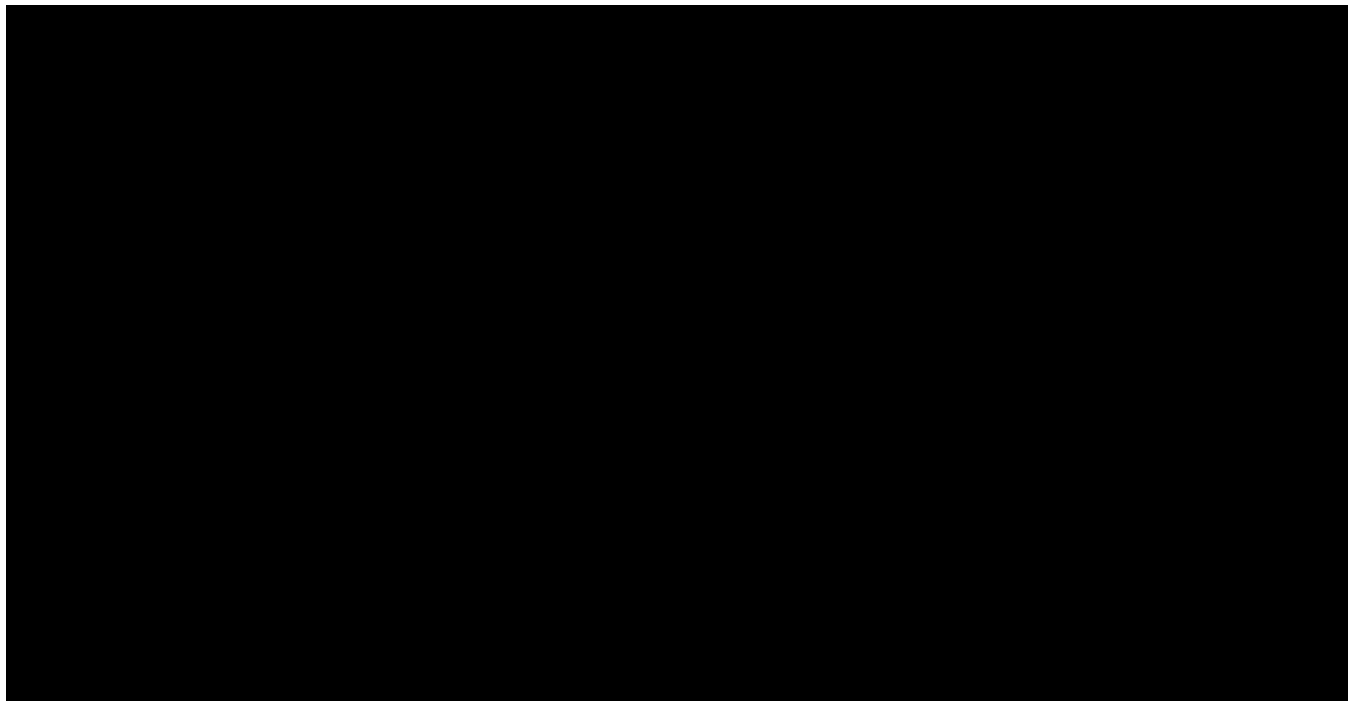
Figure 5–4: Annual growth in residential customer numbers

Source: ACIL Allen Consulting, JEN Demand Forecasts 2019-2028

5.2.1.2 Business customers

Construction activity in the non-residential sector is a key driver of the connection activities our commercial and industrial customers will require in the future. Our forecast connections capital expenditure for business customers is developed from forecasts of the value of construction activity in the non-residential sector. Specifically, we use the ACIF forecasts of building and construction activity for the industrial, other commercial and miscellaneous non-residential sectors in Victoria, which are shown in Figure 5–5. Activity in this sector is forecast to continue to grow throughout the next regulatory period, consistent with positive trends in Victoria’s population and gross state product.

Figure 5–5: Value of non-residential sector construction activity in Victoria



Source: Based on Australian Construction Industry Forum, Australian Construction Market Report, May 2019.

5.2.2 General connections expenditure forecast

We used an adjusted average of our annual connections capital expenditure for calendar years 2016 to 2018 as the basis of our general connections expenditure forecast, split into the four connection subcategories as preferred by the AER. We consider this represents a prudent and efficient basis of our forecast, as:

- it reflects the most recently available audited information
- we have adjusted this ‘base’ level of expenditure to remove major customer connection projects (above 10 MW), as these projects are less suited to forecasting on a top-down basis
- using an average of multiple years of expenditure reduces the potential for our forecast expenditure to be skewed by outlier projects in any single year of historical data
- it reflects the service classification for connections services which will apply during the next regulatory period

- consistent with the requirements of NER clause 6.5.7(c), this base level of expenditure reflects the efficient level of expenditure required in a single year to achieve the capital expenditure objectives,⁷³ noting that a significant degree of our connections expenditure is subject to contestability under our Connection Policy,⁷⁴ therefore providing competitive tension.

We calculated our forecast gross connections capital expenditure for general connections projects by applying the projected growth rates in residential customer numbers (for the residential and subdivision subcategories) and non-residential construction activity (for the commercial/industrial subcategory) to the relevant segments of our adjusted base expenditure. We then applied real cost escalation to our forecast, consistent with other categories of our capital expenditure forecast. Together, these two steps in our forecasting methodology ensure our forecast reflects the expected demand for services and the cost inputs required to achieve the capital expenditure objectives during the next regulatory period.⁷⁵ Our forecast gross connections capital expenditure for routine projects is shown in Table 5–3.

Table 5–3: Forecast expenditure for general connections (\$ June 2021, millions)

Connection subcategory	FY22	FY23	FY24	FY25	FY26	Total
Residential	10.3	10.0	10.2	10.4	10.2	51.2
Commercial/industrial	13.9	14.2	14.8	15.3	15.8	73.9
Subdivision	11.2	10.9	11.1	11.4	11.2	55.8
Embedded generation	0.0	0.0	0.0	0.0	0.0	0.0
Gross connections expenditure	35.4	35.2	36.1	37.0	37.2	181.0
Capital contributions	20.0	19.7	20.1	20.5	20.4	100.8
Net connections expenditure	15.4	15.5	16.0	16.5	16.8	80.2

5.3 Major customer connection projects

Major customer connection projects are those where a customer requires a supply for maximum demand above 10 MW. These project activities and costs are forecast on a bottom-up basis using the information provided by individual large customers about their future connection requirements. As such, this expenditure is predominately driven by factors specific to the individual customers and reflects a level of activity which is above our general connections expenditure forecasts derived from macro-economic drivers.⁷⁶

To develop our forecast of major customer connection projects, we first gather information from our engagement directly with our largest customers (including prospective customers). We then identify projects which have a high probability of proceeding during the forecast period, again making this assessment based on our engagement with customers. For each project, we develop a bottom-up cost estimate of the works required (both connection assets and upstream), consistent with our Cost Estimation Methodology, to arrive at our forecast of gross capital expenditure. We also develop individual forecasts of the capital contributions required for each of these projects, consistent with our Connection Policy.

These projects are large in size and complexity. As such, there can be long lead times between the planning, customer acceptance and completion stages of such projects. There are cases where we undertake connection studies and develop multiple options to present to the customer. In cases where a customer has yet to commit to a specific option, but there is a high probability that the project will proceed in some form, we have included the option which we consider is most likely to be selected by the customer in our forecast.

⁷³ NER cl 6.5.7(a).

⁷⁴ Attachment 05-09.

⁷⁵ Consistent with NER cl 6.5.7(c)(3).

⁷⁶ We adjust the base years of our general connections expenditure to remove major customer connection projects above 10 MW to avoid the potential for double counting such projects in our forecast.

Our major customer connection project gross capital expenditure over the forecast period totals \$20.5M, and comprises five customer projects, including new or upgraded supply to:

- the new Footscray Hospital—this \$1.5 billion facility will contain 504 hospital beds
- the YarraBend development (Alphington)—a new mini-suburb of over 1,900 dwellings and multi-level commercial and retail facilities
- the Moonee Valley Racecourse redevelopment (Moonee Ponds)—construction of a new grandstand, commercial centre and residential precincts containing 2,000 new dwellings
- the North East Link project for tunnel construction and operation—three-lane twin tunnels travelling for six kilometres to connect the M80 and Eastern freeways
- one large data centre.

Table 5–4 sets out our forecast major customer connection project capital expenditure by connection subcategory. Details on each of these projects are provided as appendices to our Customer Initiated Capex forecast report (provided in our response to the Reset RIN).

Table 5–4: Forecast expenditure for major customer connection projects (\$ June 2021, millions)

Connection subcategory	FY22	FY23	FY24	FY25	FY26	Total
Residential	0.0	0.0	0.0	0.0	0.0	0.0
Commercial/industrial	10.8	6.3	7.6	8.2	4.2	37.1
Subdivision	0.0	0.0	0.0	0.0	0.0	0.0
Embedded generation	0.0	0.0	0.0	0.0	0.0	0.0
Gross connections expenditure	10.8	6.3	7.6	8.2	4.2	37.1
Capital contributions	6.1	3.2	3.4	2.6	1.3	16.6
Net connections expenditure	4.7	3.1	4.3	5.6	2.8	20.5

5.4 References

Supporting documents included as part of our regulatory proposal or response to the Reset RIN for our forecast connections capital expenditure are listed below.

Document title	Location
Attachment 05-03 ACIL Allen Electricity demand forecasts report	Regulatory proposal
Customer Initiated Capital Summary Report	RIN Response
Customer Connections Forecast Methodology	RIN Response

6. Augmentation expenditure

6.1 Summary

Augmentation expenditure enlarges our network and its capacity to distribute electricity or improves the quality or capability of the distribution network.

Our augmentation expenditure objectives:

- Meet or manage changes in energy demand from our customers, allowing us to maintain our current levels of network reliability (including the frequency and length of network outages) at the most efficient cost over the long term
- Efficiently minimise any constraints on grid exports from distributed energy resources to the extent possible
- Manage safety, environmental, physical security and cybersecurity risks to as low as practicable at the most efficient cost over the long term, and comply with all relevant safety and environmental obligations

Our capital expenditure forecast for the next regulatory period comprises \$146M of augmentation expenditure. This represents a 58 per cent increase in augmentation expenditure from our actual expenditure during the current regulatory period. This augmentation expenditure forecast, in combination with our total capital and operating expenditure forecasts, represents the most efficient level of aggregate expenditure to deliver the objectives set out above.

We have presented our augmentation expenditure forecast using two categories, which reflect some key differences in the underlying drivers of our forecast:

- **demand driven augmentation expenditure** responds to forecast growth in the maximum demand of our customers
- **non-demand driven augmentation expenditure** responds to factors other than maximum demand growth, including emerging power quality issues and regulatory compliance obligations.

Our augmentation expenditure forecast includes:

- a significant increase in augmentation expenditure driven by factors other than maximum demand—with this now being the largest part of our augmentation forecast—including:
 - environmental, safety and legal compliance, most notably the mandatory installation of Rapid Earth Fault Current Limiters (**REFCL**) for bushfire mitigation.
 - expenditure under our Future Grid program to improve planning, real-time monitoring and the accommodation of two-way power flows on the network (representing the most efficient option to enhance the network's ability to host DER exports and accommodate increased local energy trading by customers in the future⁷⁷) and to optimise network utilisation and future investment decisions
 - the augmentation of distribution substations to address other power quality issues and ensure we can maintain compliance with applicable regulatory obligations⁷⁸
- demand-driven augmentation expenditure in line with our actual demand-driven augmentation expenditure during the current regulatory period (in aggregate):
 - during the current regulatory period, we have focussed on investing to address the capacity risk⁷⁹ associated with several sub-transmission assets and zone substations

⁷⁷ Note some of the expenditure under this program is categorised as non-network IT capital expenditure.

⁷⁸ Including power quality obligations contained in the Victorian Electricity Distribution Code.

⁷⁹ Under our network planning methodology, 'capacity risk' refers to the quantified risk of expected unserved energy

- over the forecast period, network-wide maximum demand growth is forecast to be relatively slow, although some localised areas of the network will continue to experience strong (above 3 per cent per annum) peak demand growth over the forecast period
- our demand-driven augmentation over the forecast period is therefore focussed on smaller local areas within our network—particularly high voltage feeders and distribution substations
- we have not included expenditure to establish a new zone substation at Craigieburn in the forecast period, and have instead proposed to manage customer supply risk in this area using smaller feeder projects over the forecast period.

Figure 6–1 shows our historical and forecast augmentation expenditure, with our REFCL, Preston conversion and Future Grid programs shown as individual categories as these are major one-off or new programs whose expenditure is not comparable with longer-term trends. Figure 6–2 illustrates the significant shift in the *drivers* of augmentation expenditure over the last decade, moving from demand-driven to non-demand driven (this figure also shows our REFCL program separately to other non-demand driven expenditure). Our forecast augmentation expenditure by driver and asset type is presented in Table 6–1.

Figure 6–1: Augmentation expenditure (\$ June 2021, millions)

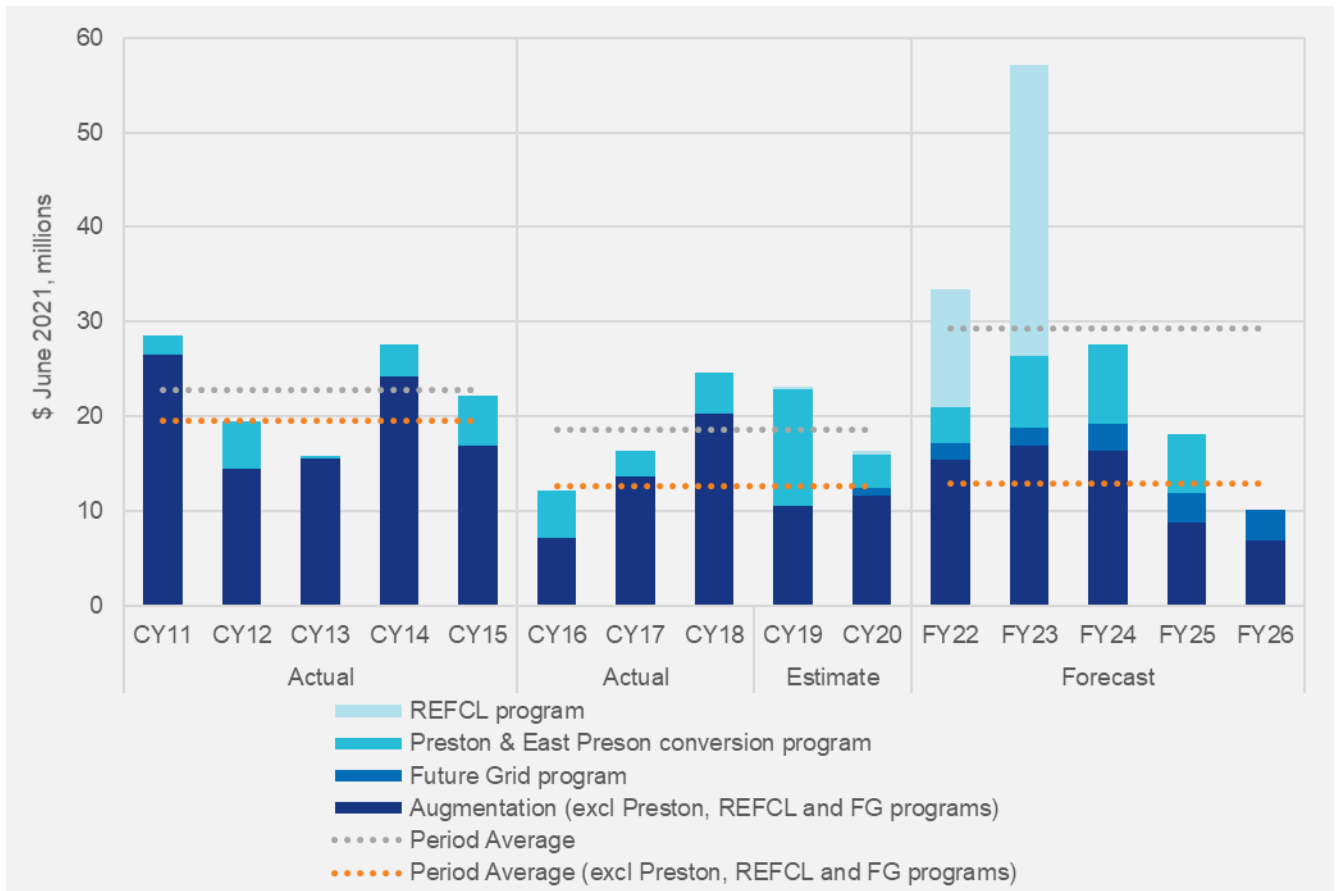


Figure 6–2: Historical and forecast augmentation expenditure by driver (\$ June 2021, millions)

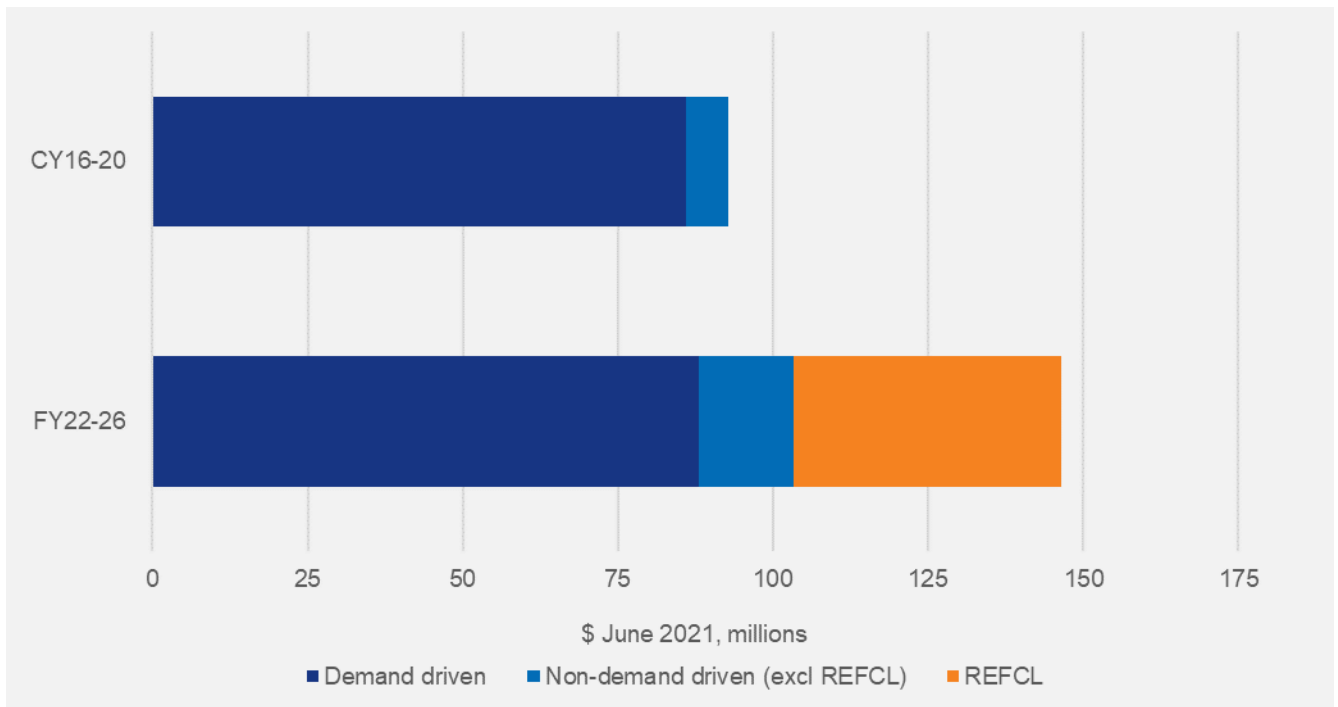


Table 6–1: Forecast augmentation expenditure by driver and asset type (\$ June 2021, millions)

Augmentation expenditure by asset type		FY22	FY23	FY24	FY25	FY26	Total
Demand driven	Subtransmission Substations, Switching Stations, Zone Substations	4.1	3.8	1.2	0.5	0.5	10.1
	Subtransmission Lines	4.8	6.5	3.9	0.0	0.0	15.2
	HV Feeders	6.8	10.7	16.5	11.1	3.2	48.3
	Distribution Substations	2.6	2.7	2.7	2.7	2.7	13.3
	LV Feeders	0.2	0.2	0.2	0.2	0.2	1.0
	Other assets	0.0	0.0	0.0	0.0	0.0	0.0
Sub-total – demand driven		18.6	23.8	24.5	14.5	6.6	88.0
Non-demand driven	Subtransmission Substations, Switching Stations, Zone Substations	10.7	25.2	0.3	0.3	0.0	36.6
	Subtransmission Lines	1.2	4.8	0.0	0.0	0.0	6.0
	HV Feeders	0.6	0.7	0.0	0.1	0.1	1.6
	Distribution Substations	1.6	1.9	2.2	2.5	2.6	10.7
	LV Feeders	0.5	0.5	0.5	0.5	0.5	2.4
	Other assets	0.3	0.3	0.3	0.3	0.3	1.4
Sub-total – non-demand driven		14.9	33.3	3.2	3.7	3.5	58.5
Total augmentation expenditure		33.4	57.1	27.7	18.2	10.1	146.5

6.2 Demand-driven augmentation

6.2.1 Forecast maximum demand growth

Traditionally, most network augmentation needs were driven by an increase in customers' maximum demand and its impact on customer supply risk. For demand-driven network augmentation planning, we employ two approaches—probabilistic and deterministic. Differences between these approaches are summarised below and explained further in our RIN Response – *JEN - Network Augmentation Planning criteria paper*.

Probabilistic planning is our principal planning method and represents a risk-based cost-benefit approach to network augmentation. This approach involves identifying individual network limitations or constraints and calculating the cost to customers of not serving energy (using the Value of Customer Reliability (VCR)⁸⁰) if the constraint is not addressed. This cost is then assessed against network and non-network options to mitigate the constraint, and the option (including doing nothing) which maximises the net benefit to customers is selected.

We apply probabilistic planning to assets where the most critical network constraints can occur and which involve the highest augmentation costs:

- transmission connection points
- sub-transmission lines
- zone substations

⁸⁰ The VCR values we use in our planning are based on the 2014 values determined by AEMO. On 18 December 2019 the AER published new VCR values, and we did not have time to systematically analyse and make changes to our capital expenditure forecast, and then go through the various internal approval and governance process whilst still meeting the submission deadlines. Our preliminary view is that the revised VCR may increase JEN's forecast augmentation capital expenditure, however we will consider this in further detail when developing our revised regulatory proposal.

- HV feeder lines when demand is forecast up to the maximum safe loading limit.

For distribution substations and LV assets, we operate and plan our network based on the full capacity of these assets. This involves defining the maximum permissible loading on an asset, and then augmenting the asset once its maximum safe loading limit is forecast to be breached. This methodology is appropriate for these lower-level assets because this planning methodology is less expensive and quicker to undertake, representing a more efficient planning approach for lower-cost assets. Furthermore, the highly-granular spatial demand forecasts necessary to undertake probabilistic planning for the localised loads connected to these assets would likely be subject to a high degree of error, exposing customers to higher supply risk.⁸¹ We apply this planning approach to HV feeders when demand is forecast to exceed the maximum safe loading limit and distribution substations and associated LV networks.

Maximum demand forecasts are a critical input to determining levels of forecast customer supply risk and therefore, demand-driven network augmentation planning, particularly under a probabilistic approach. We engaged independent energy forecasting experts ACIL Allen Consulting to prepare system-wide level maximum demand forecasts for our network. These forecasts are developed on a top-down basis for summer and winter using econometric models with input data such as customer numbers, economic growth, electricity prices, weather and the take-up and impacts of new energy technologies.

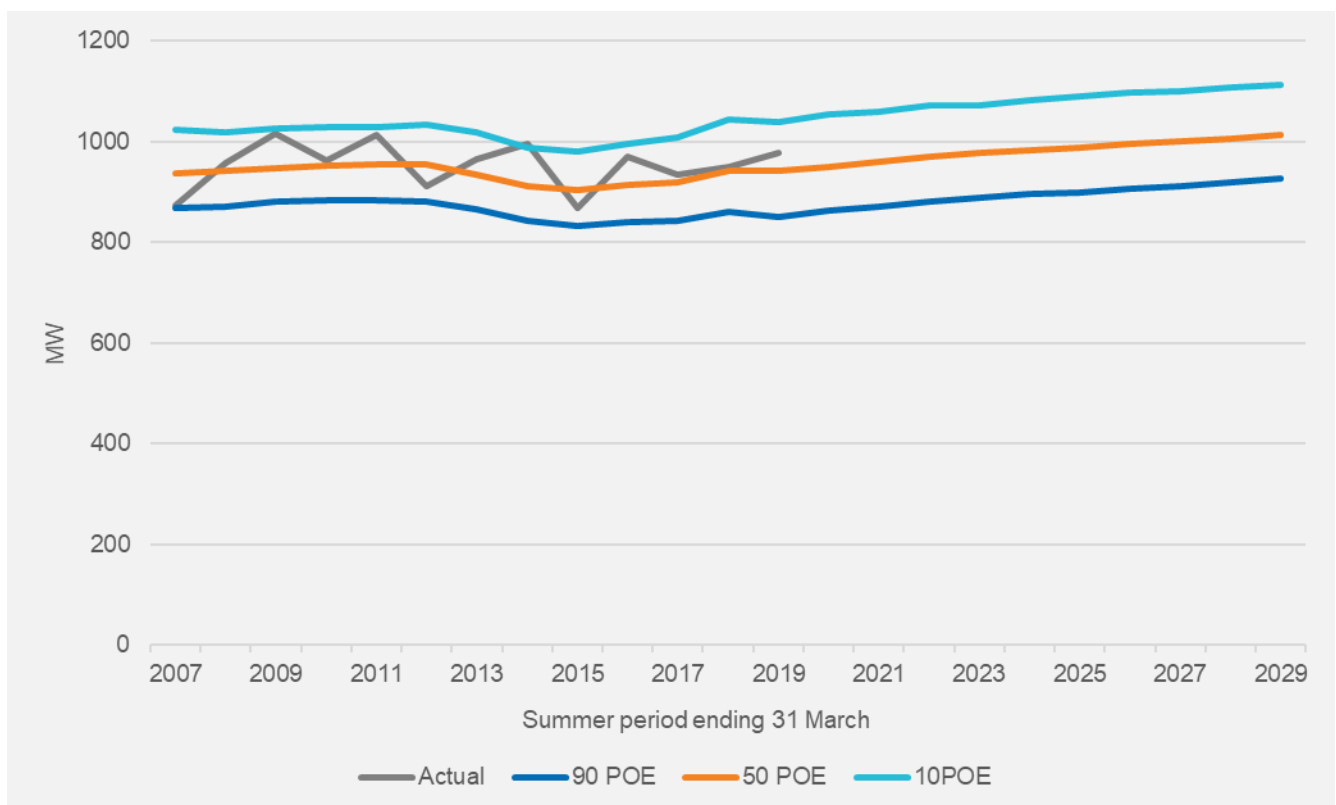
At a system level, summer⁸² maximum demand is forecast to grow at 0.8 per cent per annum between 2019 and 2026⁸³ (based on a 50 per cent probability of exceedance⁸⁴). Figure 6–3 shows our historical and forecast system maximum demand at the 10, 50 and 90 POE levels. For further information about ACIL Allen's maximum demand forecasting methodology and results, refer to Attachment 05-03.

⁸¹ Noting that customers bear supply risk under a probabilistic augmentation approach, and one key source of this risk is the accuracy of the demand forecast.

⁸² At a system-wide level, our network is summer peaking (reflecting air conditioning load), however individual feeders may experience their maximum demand during winter.

⁸³ Years refer to the summer period ending 31 March.

⁸⁴ We refer to a 50 POE forecast here as this reflects the level of forecast demand where it is equally likely that actual demand will or will not exceed the forecast.

Figure 6–3: Summer system maximum demand (MW)

Source: ACIL Allen Consulting, JEN Demand Forecasts 2019-2028

Load growth is not uniform across our distribution network, and the system-wide average of maximum demand can mask significant spatial differences in localised demand growth and the emergence of network constraints. Despite system maximum demand growth remaining somewhat subdued, there are areas within our network where maximum demand is forecast to grow well beyond the network average level, and other areas which are expected to grow well below the average rate (or where maximum demand growth is expected to be negative).

It is maximum demand growth and network constraints at these localised levels—rather than the total system level of maximum demand—which drives the need to augment the network. As explained above, we apply our probabilistic planning method to assess customer supply risks associated with individual assets such as zone substations and HV feeders. We develop bottom-up spatial maximum demand forecasts for each feeder in our network, which are reconciled to the system maximum demand forecasts. Our spatial maximum demand forecasting process and forecasts are explained further as part of our RIN Response.⁸⁵

Our spatial demand forecasts show significant variability in demand growth across our network, reflecting the varied economic and urban development factors at play across north-west greater Melbourne. Table 6–2 sets out our supply areas according to their growth rates and these are shown on a map of our network area in Figure 6–4.

⁸⁵ Refer to JEN PR0507 Internal Load Demand Forecast Procedure and JEN Internal Demand Forecast Report 2019.

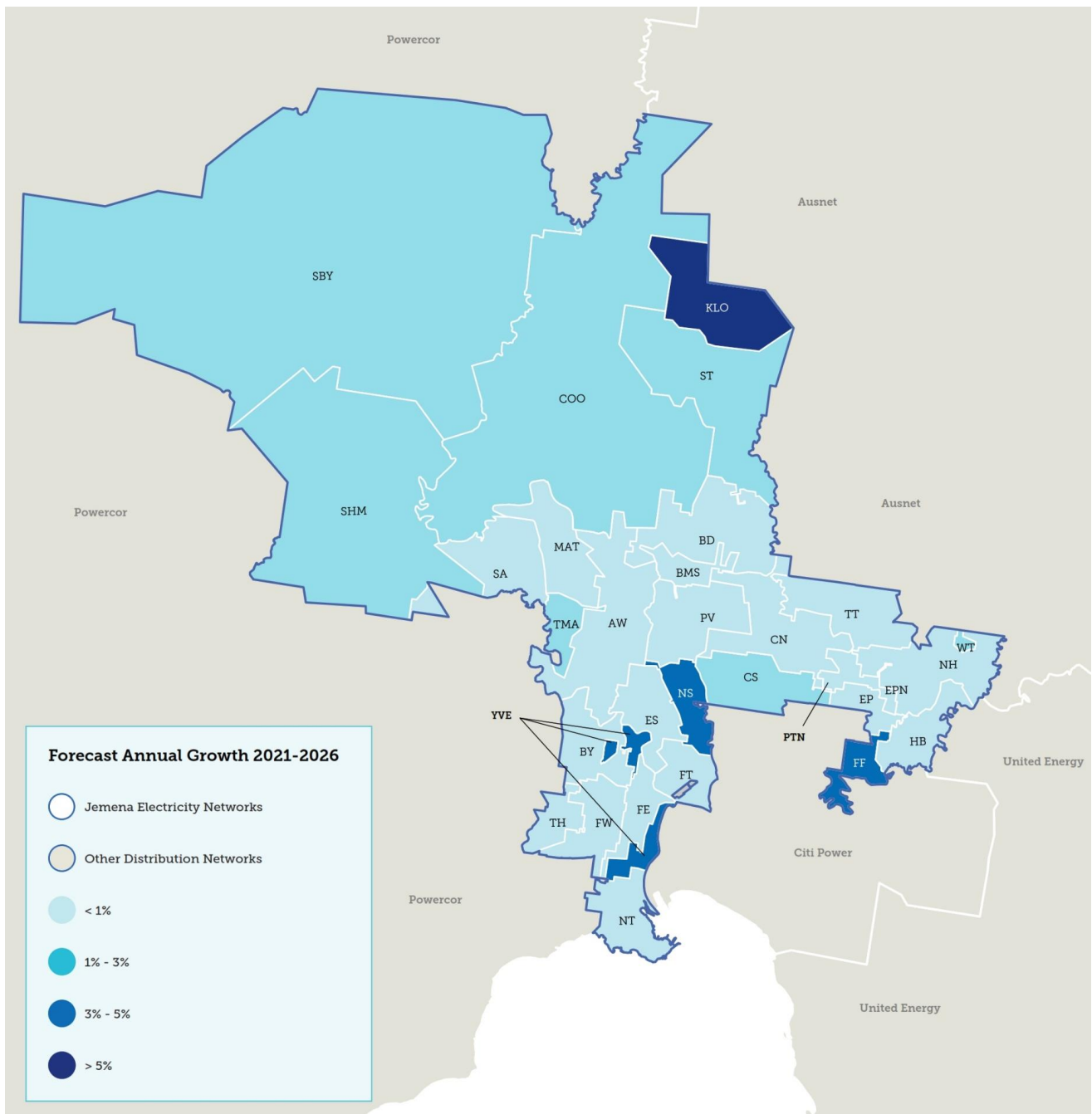
Table 6–2: Average annual maximum demand growth of JEN supply areas, 2022 to 2026

Strong growth (>5% p.a.)	High growth (3-5% p.a.)	Medium growth (1-3% p.a.)	Low growth and possible decline (<1% p.a.)
Kalkallo	Fairfield, North Essendon, Yarraville	Braybrook, Coburg South, Coolaroo, Flemington, Footscray East, Somerton, Sydenham, Watsonia	Airport West, Broadmeadows, Newport, Preston, Broadmeadows South, Coburg North, Essendon, Footscray West, Heidelberg, North Heidelberg, East Preston, Tullamarine, Pascoe Vale, Sunbury, St. Albans, Thomastown, Tottenham

(1) Refers to 50 POE summer maximum demand.

(2) Customer-specific zone substations not shown.

Figure 6–4: Forecast summer maximum demand growth by zone substation supply area



(1) Refers to 50 POE summer maximum demand.

6.2.2 Our main demand-driven augmentation projects and programs

Consistent with our probabilistic network augmentation planning methodology, our forecast demand-driven augmentation expenditure is targeted at areas of forecast high summer maximum demand growth, such as Kalkallo and Fairfield. During the current regulatory period, we undertook several significant zone substation augmentation projects, including at Sunbury, Flemington and Preston. Having completed these works and successfully addressed these zone substation constraints, we are entering into a period where less demand-driven augmentation expenditure will be required at a zone substation level.⁸⁶ For example, our assessments of customers load at risk over the next seven years have shown far fewer zone substation constraints are expected

⁸⁶ Although our forecast capital expenditure for the next regulatory period does not currently include the construction of a new zone substation in the Craigieburn area, with this project instead planned for the following regulatory period based on our current demand forecast and the 2014 VCR. However, a new connection request from a major customer could trigger the need for this project within the next regulatory period.

to emerge during the next regulatory period. Instead, our spatial maximum demand forecasts have demonstrated the need to focus more on smaller assets such as HV feeders.

Non-network alternatives to augmentation

We assess a range of network and non-network options (including combinations of network and non-network options) and optimal timings to address network constraints identified through our augmentation planning processes, consistent with the requirements of the Regulatory Investment Test for Distribution (**RIT-D**). We also assess non-network options as part of our asset replacement planning processes for non-routine projects such as zone substation projects (where different capacity alternatives exist), as described in section 4.2.

Depending on the identified constraint and its associated risks, non-network options we may consider include:

- embedded generation—small and large scale, dispatchable and non-dispatchable, and of various generation fuel types
- energy storage
- demand response (voluntary curtailment of customer load)
- customer power factor correction
- customer energy efficiency.

Despite our forecast capital expenditure for the next regulatory period containing only two demand-driven augmentation projects or programs exceeding the RIT-D estimated capital cost threshold of \$6 million, we have thoroughly examined non-network alternatives for all of our proposed demand-driven network augmentation programs relating to constraints at a sub-transmission, zone substation or HV feeder level.

Consistent with the RIT-D framework requirements and our assessment process for network options, we consider the viability of non-network options as alternatives to network investment using an economic cost-benefit framework, enabling us to select the option which maximises the net benefit to customers. These assessments have also built on our experiences and learnings during the current regulatory period from our demand management trials, such as the Power Changers residential demand response project, in addition to the knowledge we gather through consultation processes on RIT-D projects.

Overall, for the demand-driven network constraints we propose to address during the next regulatory period, we have identified that demand management would provide a lower net economic benefit to customers than network augmentation in each case. At this time, we believe the most significant impediments to the economic deployment of non-network solutions to demand-driven network constraints are:

- the high cost of implementing and scaling demand management solutions
- the inability to attain required firmness in demand response capacity
- still developing market maturity in terms of technology and service providers
- the lead time required to implement demand management to address network needs.

However, we will continue to reconsider the economic viability of demand management and other non-network alternatives when commencing projects within the next regulatory period as technology continues to rapidly evolve.

Further details on our demand management initiatives to date and our non-network option assessment methodology are contained in our RIN Response – *Demand Management Options Analysis report*, while results of non-network options analysis for each identified network constraint are presented as part of our network development strategies or business cases.

The sub-sections below provide a brief overview of our main demand-driven augmentation projects during the next regulatory period, the forecast expenditures for which are shown in Table 6–4.

Table 6–3: Main demand-driven augmentation projects and programs (\$ June 2021, millions)

Project/program name	FY22	FY23	FY24	FY25	FY26	Total
Construction, upgrade or reconfiguration of high voltage feeders	6.2	5.6	7.5	4.3	2.6	26.2
Brunswick Terminal Station-North Essendon sub-transmission upgrade	4.8	5.3	0.0	0.0	0.0	10.1
Fairfield/Alphington supply	0.1	1.4	4.4	0.0	0.0	5.8
Preston conversion program	4.1	7.9	8.6	6.2	0.0	26.8
Distribution substation augmentation (load driven)	2.8	2.9	2.9	2.9	2.9	14.3
Other projects	0.6	0.8	1.1	1.1	1.1	4.7
Total demand driven augmentation capital expenditure	18.6	23.8	24.5	14.5	6.6	88.0

6.2.2.1 Construction, upgrade or reconfiguration of high voltage feeders

Our network includes 217 HV feeders, 121 of which are forecast to have load at risk under normal or single contingency conditions during the next regulatory period. Of these, 33 are forecast to have significant load at risk and 25 are forecast to exceed their maximum safe loading limit by summer 2025-26.⁸⁷ Having undertaken cost-benefit analysis in line with our network planning methodology, we propose to augment 26 of these feeders to address load at risk during the next regulatory period to meet growing demand from our customers—18 of these due to exceeding their safe loading limit and eight of these due to significant load at risk under single contingency conditions. Supply risks associated with a further seven feeders will be addressed through other projects, as part of feeder transfers or through customer-initiated works. The optimal timing for the remaining 88 feeders was determined to be later than FY26. Works proposed to alleviate identified HV feeder constraints include:

- construction of new feeders (from existing zone substations)
- replacing existing feeders with higher-rated conductors or cables or implementing other measures to increase the thermal rating of existing conductors or cables
- modifying the configuration of feeders, such as through creating tie-lines to increase emergency or permanent transfer capacity and enable the optimisation of utilisation between feeders.

We examined non-network alternatives to our proposed feeder augmentation projects, including embedded generation, energy storage, demand management (including direct load control) and voltage reduction. In all cases, these were not found to represent options which maximised net benefit to customers, due to their high cost, a lack of firmness in demand response and still developing market maturity of technologies and service providers. However, we will continue to assess the viability of non-network alternatives closer to the time of each project's implementation as part of our capital planning and business case process.

The demand-driven feeder augmentation projects contained in our forecast capital expenditure for the next regulatory period are set out in Table 6–4. Further information about these projects is contained in our RIN Response – *Distribution Feeders Network Development Strategy*.

⁸⁷ Under a 10 POE maximum demand forecast.

Table 6—4: Proposed feeder augmentation projects

Supply areas	Project title	Completion date
Yarraville	Reconfigure Feeder YVE11	FY22
Footscray East	Augment Feeder FE06	FY24
Newport	Augment Feeder NT11	FY23
Flemington	New Feeder FT12	FY26
North Essendon	Augment Feeder NS18	FY24
North Essendon	Augment Feeder NS15	FY27
Essendon	Reconfigure Feeder ES23	FY22
Sunbury	Augment steel section of Feeder SBY14	FY27
Tullamarine	New Feeder TMA15	FY25
Sunbury	Reconfigure Feeder SBY24	FY25
Kalkallo	Reconfigure Feeder KLO21	FY23
Coolaroo, Somerton	COO22 and ST32 Capacity Constraint	FY25
Heidelberg	New Feeder HB21	FY24
Broadmeadows, Somerton	BD08, BD13 & ST34 Capacity Constraint	FY25

6.2.2.2 BTS-NS sub-transmission upgrade

Demand in the North Essendon zone substation's (**NS**) supply area is expected to grow by 3.2 per cent annum on average during the next regulatory period, primarily driven by the proposed residential and commercial developments around Moonee Valley racecourse.⁸⁸ The Moonee Valley Racecourse's vision and plan for its site include the construction of a new grandstand, commercial centre and residential precincts containing 2,000 new dwellings, with the first stage of works having commenced in 2018.

The three existing 22 kV sub-transmission lines which supply North Essendon from Brunswick Terminal Station (**BTS**) are currently fully utilised, and the loss of one of these lines in summer 2020/21 would lead to the loss of supply to around 4,500 customers in the Essendon, Strathmore and Moonee Ponds areas. Furthermore, two of the three sub-transmission circuits share the same poles, increasing the risk that two lines are lost as a result of a single event (such as a motor vehicle accident), which would result in the loss of supply to all 10,500 customers in the NS area.

In light of the forecast load growth and the current sub-transmission lines being unable to accommodate this, it is prudent to consider options to reduce the supply risk to customers in the North Essendon area. We have assessed a range of options to alleviate the forecast sub-transmission constraints and propose to undertake works to upgrade all three sub-transmission lines to a higher rating. Our proposed works include constructing a new sub-transmission circuit (comprising both overhead and underground segments) from BTS to NS (eliminating the current risk posed by the use of the same poles for two circuits) and thermally uprating conductors on the existing circuits.

Our options analysis considered using demand management to mitigate load at risk for two years and defer investment in the most economic permanent network solution, however, this option would result in a lower net economic benefit to customers than our proposed solution. We also considered using grid-scale batteries in place of sub-transmission line upgrades. However, this would involve substantially higher costs while not mitigating supply risks to the same extent as our proposed investment.

⁸⁸ Our capital expenditure forecast also includes connections expenditure associated with this development, refer to section 5.3.

Further detail on this project is contained in our RIN Response – *BTS-NS Subtransmission Network Development Strategy*.

6.2.2.3 Fairfield/Alphington supply

Demand in Fairfield zone substation's supply area is expected to grow on average by 3.6 per cent per annum during the next regulatory period due to the YarraBend development, a major urban infill development project involving the construction of 1,900 new residential dwellings and multi-level commercial and retail buildings at the former Amcor Paper Fairfield site.⁸⁹ The existing sub-transmission lines which supply Fairfield zone substation and the feeders emanating from it are currently fully utilised and will not have sufficient capacity to meet this forecast increase in demand, posing significant customer supply risk during the next regulatory period, in addition to safety risks associated with overloaded conductor clearance limits being breached.

The risk to customer supply is compounded as the Fairfield supply area will become an isolated 6.6 kV network (a legacy voltage standard) once its neighbouring Preston and East Preston zone substations are converted to the modern 22 kV standard in 2022, which will remove transfer capability from Fairfield zone substation in the event of a major outage at the station or in the upstream sub-transmission network.

During the current regulatory period we commenced works to maintain reliability in the Fairfield supply area by replacing two deteriorating zone substation transformers and reconfiguring other equipment. In the next regulatory period, we propose to:

- construct a new underground sub-transmission line from Brunswick Terminal Station to supply Fairfield zone substation, including installation of a ring bus in Fairfield zone substation
- construct two new underground 6.6 kV feeders from Fairfield zone substation to supply the YarraBend development area.

A further two feeders would be constructed in the 2026-31 regulatory period. Consistent with the approach we employed to replacing the two deteriorating Fairfield transformers this regulatory period, the above works will allow for the Fairfield supply area to be economically converted from 6.6 kV to 11 kV in the future, consistent with our long term objective of removing all 6.6 kV network when economic to do so.

We assessed permanent non-network options of battery storage and embedded generation in addition to using demand management to defer implementation of a permanent network solution. Permanent battery storage and embedded generation options are not viable due to their significantly higher cost, inability to adequately address feeder constraints and practicality issues installing such equipment in a mostly residential area.

In our options analysis, we also considered using demand management to mitigate load at risk for two years before implementing a permanent network solution on a delayed basis. As Fairfield zone substation mainly supplies residential customers and there are no single large customers in the area, any effective demand management initiative would need to achieve peak load reductions from residential customers. The costs of attaining peak demand reduction from residential customers through demand management are higher than for industrial and commercial customers. Furthermore, the Fairfield supply area contains a higher proportion of residential customers who, based on demographic segmentation analysis such as household income used in our recent demand response trials, are less likely to choose to participate in a demand response program.

Further detail on these projects is contained in our RIN Response – *Fairfield/Alphington Network Development Strategy*.

6.2.2.4 Preston conversion program

Prior to the Preston conversion project commencing in 2008, the Preston area was entirely supplied by the Preston (P) and East Preston (EP) zone substations operating at 6.6 kV distribution voltage. These assets were established in the 1920s and underwent refurbishment in the 1950s and 1960s.

⁸⁹ Our capital expenditure forecast also includes connections expenditure associated with this development, refer to section 5.3.

Our condition based assessments of the equipment at P and EP zone substations showed the assets reaching the end of their useful lives in 2014 and 2020 respectively. Both zone substations also posed a number of health and safety risks to staff and the public. In addition to the deteriorating condition of these assets, urban infill in the area has seen load growth and would have caused constraints on the 6.6 kV system. Given the lower transfer capacity of 6.6 kV feeders, more feeders would be required to maintain the reliability of supply to customers in this area during times of peak demand, with this also posing challenges due to overhead network congestion in road reserves within this brownfield area. Installation of new underground 6.6 kV feeders would also lead to comparatively higher costs for customers connecting to the network and higher electrical losses compared to a modern voltage such as 22 kV.

In light of both asset condition and load growth drivers, we considered a wide range of options to meet our customers' future supply needs in the Preston area, not only the replacement of the P and EP zone substation assets on a like-for-like basis (noting that 6.6 kV is a legacy voltage). We developed a long-term network development strategy in the early 2000s for the Preston area to analyse these options, which found that the conversion of the P and EP network from 6.6 kV to 22 kV represented the least cost and most beneficial option for our customers. Under this strategy, works would be completed in multiple stages, the first of which commenced in 2008. As at the end of 2019, we have completed 9 of 14 stages within the program, as outlined in Table 6–5.

Table 6–5: Preston conversion program objectives and stages

Objective	Conversion stages	Status
1. Transfer as much load as possible away from P/EP 6.6 kV to nearby 22 kV zone substations (Coburg South, Coburg North and North Heidelberg)	P Stages 1, 2 and 3 EP Stages 1 and 2	Complete
2. Establish 22 kV supply capacity within the P/EP area to enable converting/transferring load away from P to continue	EP Stage 3	Complete – new 66 kV/22 kV assets established at the existing EP zone substation site
3. Transfer all remaining load away from P and retire P zone substation 6.6 kV assets	P Stages 4 and 5 EP Stage 4	Complete – P 6.6 kV assets retired
4. Add additional 22 kV supply capacity within the P/EP area to enable converting/transferring of load away from EP to continue, and enable some load to be transferred back from Coburg South and Coburg North to address other capacity constraints	P Stage 6	In progress – new 66 kV/22 kV assets at the existing P zone substation site will be commissioned in early CY20
5. Transfer all remaining load away from EP and retire EP zone substation 6.6 kV assets	EP Stages 5, 6, 7 and 8	Proposed to be completed by FY25

We have re-evaluated the costs, benefits and options of our Preston conversion program before the commencement of each stage. This includes analysing the potential for non-network alternatives, including through RIT-Ds we have undertaken for two of the stages to date. Our most recent update to our Preston network development strategy (prepared in April 2019) reconfirmed that continuing with the conversion program as planned represented the most prudent and efficient option to meet customers' future supply needs in the area.

The scope of works for the final four stages of the program are summarised in Table 6–6, with the works forming part of our capital expenditure forecast for the next regulatory period highlighted.

Table 6–6: Proposed future Preston conversion program works

Stage	Planned works	In service year	Included in FY22-26 capital expenditure forecast?
EP Stage 5	Conversion of EP feeders and distribution substations	CY21	No
EP Stage 6	Decommission EP 'A' zone substation and install second 66 kV/22 kV transformer at EP zone substation site	FY23	Yes
	Process bus extension at new P zone substation ⁹⁰	FY24	Yes
EP Stage 7	Conversion of EP feeders and distribution substations	FY24	Yes
EP Stage 8	Conversion of EP feeders and distribution substations. Decommission EP 'B' zone substation	FY25	Yes

Further detail on this program is contained in our RIN Response – *Preston Area Network Development Strategy*.

6.2.2.5 Distribution substation augmentation (load driven)

Ongoing growth in customers' maximum demand at localised levels of our LV network throughout the next regulatory period will continue to cause distribution substations to become overloaded, increasing the likelihood of transformer failure and heightening public safety and LV customer supply risks. The continued overloading of a transformer above specific ratings can also accelerate the deterioration of the transformer and reduce its life expectancy, therefore optimising the timing of transformer augmentation is a crucial factor in efficiently minimising the total lifecycle cost of these assets.

As set out in section 6.2.1, we apply a deterministic planning approach to the augmentation of our distribution substations and associated LV assets. Our forecast capital expenditure for the next regulatory period includes annual expenditure to continue our distribution substation augmentation program, which involves replacing distribution transformers and LV conductors with components of a more substantial capacity, or installing new distribution transformers and associated LV circuits, where forecast maximum demand exceeds the ratings⁹¹ of the transformer or associated equipment.

Our objective during the 2021-26 period is to continue to address the substations which are at the highest risk of failure, based on the degree to which they are forecast to be overloaded. We currently have approximately 6,400 distribution substations—as of 2018, 442 of these transformers were identified as having a utilisation factor above 120 per cent. Furthermore, the load on 156 of these distribution substations exceeded their nameplate rating by more than 150 per cent, and these transformers will be experiencing at least some accelerated ageing which increases their likelihood of failure earlier than their intended life. If no action is taken, our number of overloaded distribution substations will increase throughout the next regulatory period, meaning we would be unable to meet forecast customer demand and maintain the reliability of supply for customers supplied by these assets.

During the next regulatory period, we propose to continue our distribution transformer augmentation program. We have considered safety and customer supply risks when developing our program, prioritising works in the following order:

1. overloaded transformers located in the HBRA parts of our network
2. undersized older transformers (including non-standard sizes) located in older established urban areas of our network

⁹⁰ These works at P zone substation will be undertaken in conjunction with the completion of the new EP zone substation.

⁹¹ We calculate ratings for each distribution substation based on extensive engineering analysis, which includes consideration of customer types served, load patterns and transformer type.

3. the remaining overloaded transformer population, prioritised by the extent of overload.

Our RIN Response – *Network Performance Plan* provides further detail on this program, including the alternative network and non-network options considered.

Our capital expenditure forecast also contains a separate program to augment distribution substations to alleviate constraints or network issues which are not directly driven by customer maximum demand, such as power quality issues—refer to section 6.3.1.3 for further information.

6.2.2.6 Other projects

Our forecast also contains three minor augmentation projects which are demand-driven:

- installation of monitoring equipment to provide for dynamic network ratings – this activity is part of the Optimised Asset Investments initiative under our Future Grid program, refer to section 6.3.1.2.
- installation of remote monitoring and control devices on the distribution network – this relates to our ongoing program of installing new remote monitoring fault indicators and ring main units throughout the distribution network as it grows over time, ensuring we can continue to maintain reliability to customers. Under this program, we will have a particular focus on newer parts of our network (outer greenfield suburban areas) where a high proportion of assets are underground and difficult to access if a fault occurs, increasing the risk of longer customer outages.
- installation of a new 66 kV line circuit breaker at CN zone substation – we propose to undertake these minor works in conjunction with the CN station rebuild to reduce the risk that a 66 kV line fault would trip one of the three transformers at this large and highly utilised zone substation.

6.3 Non-demand driven augmentation

Factors other than customer load growth are increasingly driving our augmentation expenditure, including:

- the need for us to maintain the quality of supply from our network (in light of voltage, power factor or harmonics issues),⁹² driven by continued strong uptake of DER and our customers' expectations that our network should accommodate this forecast increase in exports from DER
- the need for us to comply with Victorian bushfire mitigation regulatory obligations.

⁹² In line with requirements set out in instruments such as the Victorian Electricity Distribution Code.

There are three main programs within our forecast of non-demand driven augmentation expenditure, which are set out in Table 6–7 and explained in the sections below.

Table 6–7: Non-demand driven augmentation programs (\$ June 2021, millions)

Project/program name	FY22	FY23	FY24	FY25	FY26	Total
REFCL program ⁹³	12.4	30.7	0.0	0.0	0.0	43.1
Future Grid program (non-demand driven augex portion ⁹⁴)	1.7	1.9	2.3	2.6	2.6	11.2
Distribution substation augmentation (power quality-driven)	0.7	0.7	0.7	0.7	0.7	3.6
Other projects	0.0	0.0	0.2	0.3	0.1	0.6
Total non-demand driven augmentation capital expenditure	14.9	33.3	3.2	3.7	3.5	58.5

6.3.1 Key non-demand driven augmentation projects and programs

6.3.1.1 Bushfire mitigation obligations – REFCL program

Victoria's *Electricity Safety (Bushfire Mitigation) Regulations 2013* (including subsequent amendments made in 2016 and 2017) (**ES Regulations**) set out mandatory safety standards for electricity companies to reduce bushfire risks. These Regulations are relatively new, having been introduced in response to Victoria's 2009 Black Saturday bushfires and the Victorian Bushfire Royal Commission. The ES Regulations set technical performance standards (referred to as the **Required Capacity**) for 45 zone substations throughout Victoria's most bushfire-prone areas, including JEN's Coolaroo zone substation (**COO**).

The Required Capacity can only be met by installing devices known as REFCLs in the respective zone substations. REFCLs are designed to limit the current that is released in a phase-to-ground fault on a high voltage line originating from the zone substation, thus reducing the risk of a bushfire caused by a fallen conductor. The *Electricity Safety Amendment (Bushfire Mitigation Civil Penalties Scheme) Act 2017* (Vic) provides for significant financial penalties in cases where a zone substation does not meet the Required Capacity by its relevant compliance date.

Under the ES Regulations, JEN is responsible for ensuring that all feeders originating from COO meet the Required Capacity by 1 May 2023. Additionally, JEN takes supply for four of its feeders in the nearby area from the Kalkallo zone substation (**KLO**) (owned by AusNet Services) which must also meet the Required Capacity by 1 May 2023. As well as overhead lines in HBRA, the supply areas of both COO and KLO include several residential estates in Melbourne's northern growth corridor where the distribution network is underground, preventing the simple installation of REFCL equipment at either zone substation.

⁹³ These figures do not include capital expenditure on REFCL test equipment and truck, which are included in our non-network expenditure forecast.

⁹⁴ Future Grid program activities classified as non-network IT expenditure are not included within the amounts shown, refer to Table 6–9 for full Future Grid program costs across all expenditure categories.

REFCL technical limitations on underground networks

Significant portions of the HV feeders originating from both COO and KLO are located underground,⁹⁵ and these underground electricity cables result in far higher capacitive currents than overhead lines.⁹⁶ Arc suppression coils, a key part of the REFCL equipment installed on each bus in the zone substation, have technical limits of network capacitive current which they can handle (depending upon network-specific damping ratios), meaning that the capacitive current for each zone substation bus cannot exceed the allowable capacitive current. This substantially limits the length of underground cables that each REFCL can protect.

Further compounding this problem are other technical limitations of current REFCL technology:

- Other DNSPs have previously identified that the capacitive current of each feeder connected to a REFCL-protected bus cannot exceed 80 A, otherwise the REFCL equipment is unable to identify the faulted feeder and operate correctly
- No more than two REFCLs can be installed in a single zone substation, as no software solution has been developed which can operate three REFCLs within a single zone substation.

These technical limitations make it extremely costly to meet the Required Capacity under the ES Regulations in areas with many underground feeders. Meeting the existing high capacitive current on COO and KLO feeders would require the installation of seven REFCLs in four zone substations (therefore necessitating the construction of two new zone substations).

Furthermore, as more new estates are constructed in Melbourne's northern growth corridor and the length of underground cables supplied by COO and KLO increases, so will the capacitance of these feeders, meaning the extent of this problem is forecast to increase over time. By 2030, the total forecast capacitive current in these supply areas would require the installation of 21 REFCLs across 11 zone substations.

Recognising the interrelationships between COO and KLO, JEN and AusNet Services engaged consultants WSP to assist in a joint planning exercise to examine several technical design options and determine the most efficient cost of meeting the requirements of the ES Regulations across both COO and KLO supply areas over the long-term. This exercise identified 24 options, of which 15 were excluded due to lack of technical feasibility or as a result of their initial cost analysis indicating that they were significantly more expensive than other options.⁹⁷ WSP then conducted high level technical, compliance and cost assessments for the remaining nine options. This assessment process included seeking guidance from the AER, Energy Safe Victoria and the Department of Environment, Land, Water and Planning in a meeting in August 2019. Following this process, WSP shortlisted three options and undertook more detailed assessments of their technical feasibility, compliance, risk and cost⁹⁸ to determine a preferred option.

Through this process, we identified that there was only one option (option 15 in the WSP report provided as Attachment 05-06) which could meet the requirements of the ES Regulations. This option is significantly more costly than other options identified (which require partial exemptions from the ES Regulations for underground sections of line which do not pose a bushfire ignition risk). However, as JEN has not obtained any exemption from the ES Regulations to date for COO, our forecast capital expenditure reflects the most prudent and efficient cost of complying with this regulatory obligation.^{99,100} JEN is in discussions with the relevant Victorian Authorities

⁹⁵ It is important to note that while underground electricity cables carry very low bushfire ignition risk (indeed the undergrounding of lines in very high bushfire risk areas was a recommendation of the Victorian Bushfires Royal Commission), the ES Regulations require all lines originating from specified zone substations to be REFCL protected, regardless of whether they are overhead or underground.

⁹⁶ Underground cables add approximately four times more capacitive current compared to overhead conductors on per kilometre basis.

⁹⁷ In addition to the technical limitations of current REFCL equipment outlined in the box above, this analysis also considered technical constraints such as the limited ability to transfer load to neighbouring zone substations and sub-transmission line capacity constraints in the area.

⁹⁸ Options were evaluated to determine the least cost to customers overall (combined JEN and AusNet Services) based on the scope of works to meet the requirements of the ES Regulations, both to comply by 2023 and maintain compliance over the whole of lifecycle.

⁹⁹ The ES Regulations fall within the meaning of a regulatory obligation or requirement as set out in the *National Electricity Law* s 2D(1)(b)(v).

¹⁰⁰ Consistent with NER cl 6.5.7(a)(2).

regarding potential exemptions from ES Regulations. Depending on the outcomes of these discussions, we may be able to amend our regulatory proposal to reflect lower cost options.

Our forecast capital expenditure includes \$43M (real June 2021) of augmentation expenditure and \$0.2M (real June 2021) of non-network expenditure to comply with the ES Regulations. The scope of the works to comply with the ES Regulations reflected in our forecast capital expenditure would result in REFCL protection of all overhead and underground lines originating from COO by 1 May 2023, through:

- Installing two REFCL devices at COO
- Constructing a new zone substation in the Greenvale area (referred to as **GVE**) and transferring some existing COO feeders to GVE. This is required as the REFCL equipment at COO would not be sufficient to meet the capacitance of all feeders in the area, noting that it is not possible to install more than two REFCLs at this zone substation. GVE would have two transformers and two REFCLs
- Undertaking network balancing¹⁰¹ network and hardening¹⁰² works on JEN feeders supplied by REFCL protected zone substations
- Purchasing specialist test equipment and a heavy commercial vehicle required for JEN to carry out the mandatory annual pre-summer earth fault testing activities^{103,104} for COO, including primary earth fault testing.

We recognise that expenditure to fully comply with the ES Regulations represents a significant cost. As noted above, we are committed to pursuing an exemption from the ES Regulations for underground feeders originating from COO which would allow us to implement a lower cost option instead while still effectively mitigating bushfire risk in the relevant areas. We expect to know the outcome of our exemption request before our revised regulatory proposal is due in December 2020. Should an exemption be granted as proposed, we will amend our revised proposal capital expenditure forecast to reflect the lower cost of complying with the ES Regulations in light of this exemption, which we consider would be in the long-term interests of our customers.

Outside of our obligations under the ES Regulations, we have not proposed to install any other REFCL devices under our forecast capital expenditure. In the longer-term, our strategy is to install REFCLs at all zone substations in the HBRA of our network, which include Sunbury zone substation and also Craigieburn zone substation when constructed after FY26.

6.3.1.2 Future Grid program

Our Future Grid program represents a set of least-regrets activities in response to changes we know will continue to occur in our energy market over the coming decades. Our proposed Future Grid program is comprised of seven activities across two initiatives—**Enabling DER** and **Optimised Asset Investment**. Despite these initiatives falling across two expenditure categories,¹⁰⁵ they are interdependent of each other to address our customers' future needs most efficiently.

Although our forecast expenditure under the Future Grid program spans both the augmentation and non-network IT capital expenditure categories (in addition to operating expenditure which we have identified as a step change in Attachment 06-05), this section presents the capital expenditure and benefits of our Future Grid program in its entirety regardless of expenditure category—as one of the program's key outcomes is to reduce the amount of augmentation capital expenditure we would otherwise need to spend in the future.

¹⁰¹ Capacitance balancing to ensure the REFCL can operate correctly.

¹⁰² Replacing equipment with insufficient insulation ratings to ensure this equipment does not fail when the REFCL operates, as the operation raises the phase to ground voltage on non-faulted phases.

¹⁰³ Capital expenditure on the test equipment and truck forms part of our non-network expenditure category, and is not included in the figures shown throughout this section.

¹⁰⁴ These testing activities are required under *Electricity Safety (Bushfire Mitigation) Regulations 2013* s 7(1)(hb). JEN has proposed an operating expenditure step change relating to these annual testing activities, refer to Attachment 06-05 for further details.

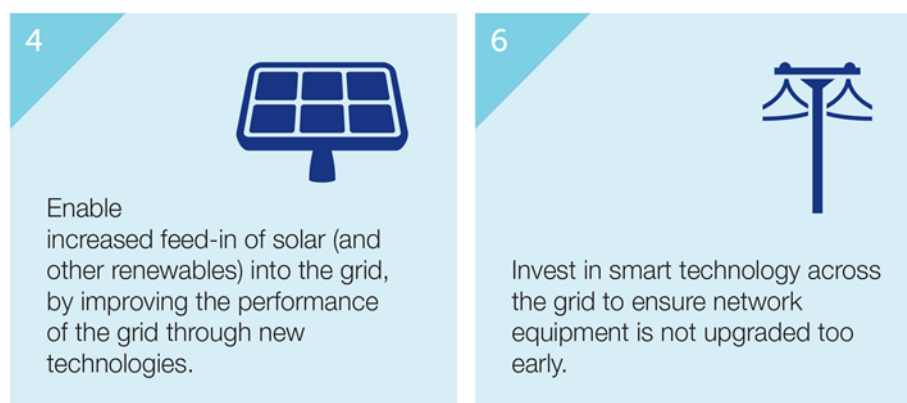
¹⁰⁵ We have presented expenditures throughout our proposal in accordance with the category definitions contained in the AER's Regulatory Information Notice. The AER's consultation paper on *Assessing DER integration expenditure* noted that DER integration expenditure cross a number of cost categories.

The capital expenditure category of each activity within our program is shown in Table 6–9. The forecast expenditure presented in section 7 of this document reflects the non-network IT expenditure portion of our Future Grid program. For full detail of our proposed activities and the cost-benefit analysis we have undertaken for our Future Grid program, refer to our Future Grid investment proposal (Attachment 05-04).

Our customers' future expectations

A key part of our engagement included seeking customers' views on how they expect to use energy in the future, what they expect the role of network service providers should be and what actions we should take to facilitate customers' energy futures. Through our engagement, customers told us that affordability, efficiency and 'future-proofing' the grid were very important to them, and also that there was a wide range of potential future energy scenarios that they considered may eventuate. Our People's Panel made two specific recommendations which our Future Grid program has been designed to respond to, shown in Figure 6–5. The Panel's recommendations had a particular emphasis on the use of new technologies to respond to these issues, recognising potential longer-term efficiency benefits to customers of this.

Figure 6–5: People's Panel recommendations informing our Future Grid program



Responding to customers' feedback

We have designed our Future Grid program to future-proof our network in a way that contributes to our customers' long-term interests under multiple future scenarios. Despite uncertainty around changes in customer expectations and behaviour, technological developments and policy and regulatory responses, our Future Grid program will ensure we are best placed to deliver services in the long-term interests of our customers by building a strong and adaptable foundation during the next regulatory period. The two initiatives under our Future Grid program are explained further below:

1. **Enabling DER** – this will build a foundation for the network to support increased two-way flows and energy trading by customers in future. It involves expenditure on network monitoring and power quality, mainly to improve visibility on the LV network to improve hosting capacity for DER
2. **Optimised Asset Investment** – this will allow us to improve network utilisation further and optimise future network investment decisions. It involves expenditure on real-time condition monitoring of network assets and other activities.

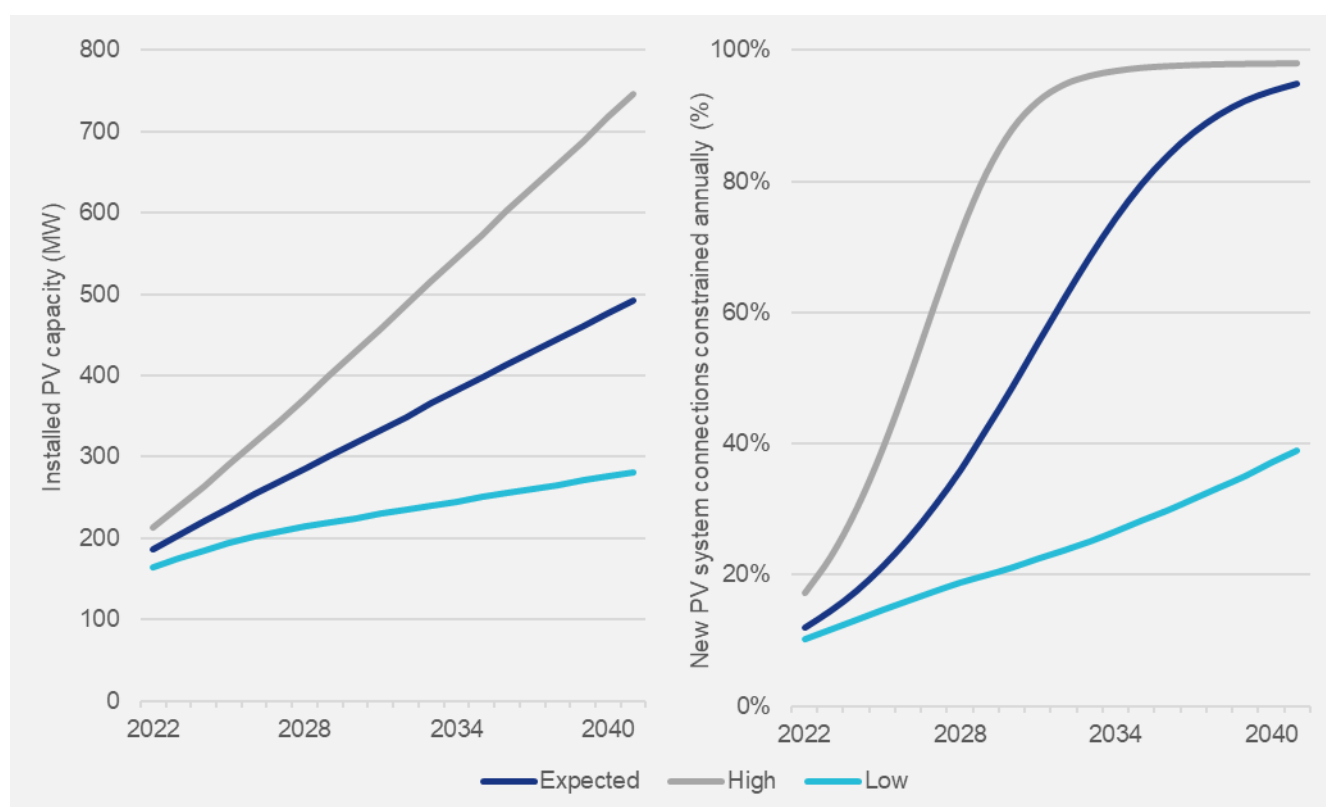
Enabling DER

The way customers are using our network is changing, and customers have told us that it will continue to change. In the future, this means more customers will install more DER and expect to be able to maximise the value from their investments by exporting to the grid, trading energy locally and accessing new energy markets.

To facilitate this, our network needs to accommodate increasingly bi-directional power flows. However, our network's ability to provide for the forecast increase in DER penetration without augmentation is limited, as high DER penetration can cause the network to operate outside of safe and reliable limits (including power quality obligations set out in the Electricity Distribution Code) and result in adverse outcomes for customers, such as solar PV inverters tripping.

Without augmenting the network or taking other actions to address these technical challenges, it would be increasingly necessary to place export limits on new DER connections in areas of the LV network where there is insufficient spare hosting capacity. This is illustrated in Figure 6–6, which shows forecasts of increasing solar PV take-up and the corresponding proportions of new solar PV connections which would need to be constrained over time.

Figure 6–6: Impact of solar PV forecasts on constrained DER connections



We examined several options in response to this challenge. In assessing these options, we applied the same framework and cost-benefit analysis approach as we use in our asset augmentation and replacement planning, consistent with the good practice approach outlined by the AER in its *Assessing DER integration expenditure consultation paper*.¹⁰⁶

We first defined and quantified the risk to customers under a counterfactual scenario which represented the outcomes over the next 20 years if we were to take no action. This scenario reflects the lost value of incremental solar PV generation due to export constraints as shown in the 'expected' series in Figure 6–6, with solar PV generation valued at Victoria's minimum feed-in tariff.¹⁰⁷ Under this counterfactual scenario, over 2,700 of our distribution substations (against a current population of around 6,500) would become constrained between 2022 and 2041, requiring the constraint of 39 per cent of new PV connections by 2041 and leading to over \$141M (real June 2019 dollars) of solar PV exports being lost over this period. We also considered the operating expenditure associated with DER connection applications under this counterfactual scenario.

¹⁰⁶ AER, *Consultation paper: Assessing DER integration expenditure*, November 2019, section 6.

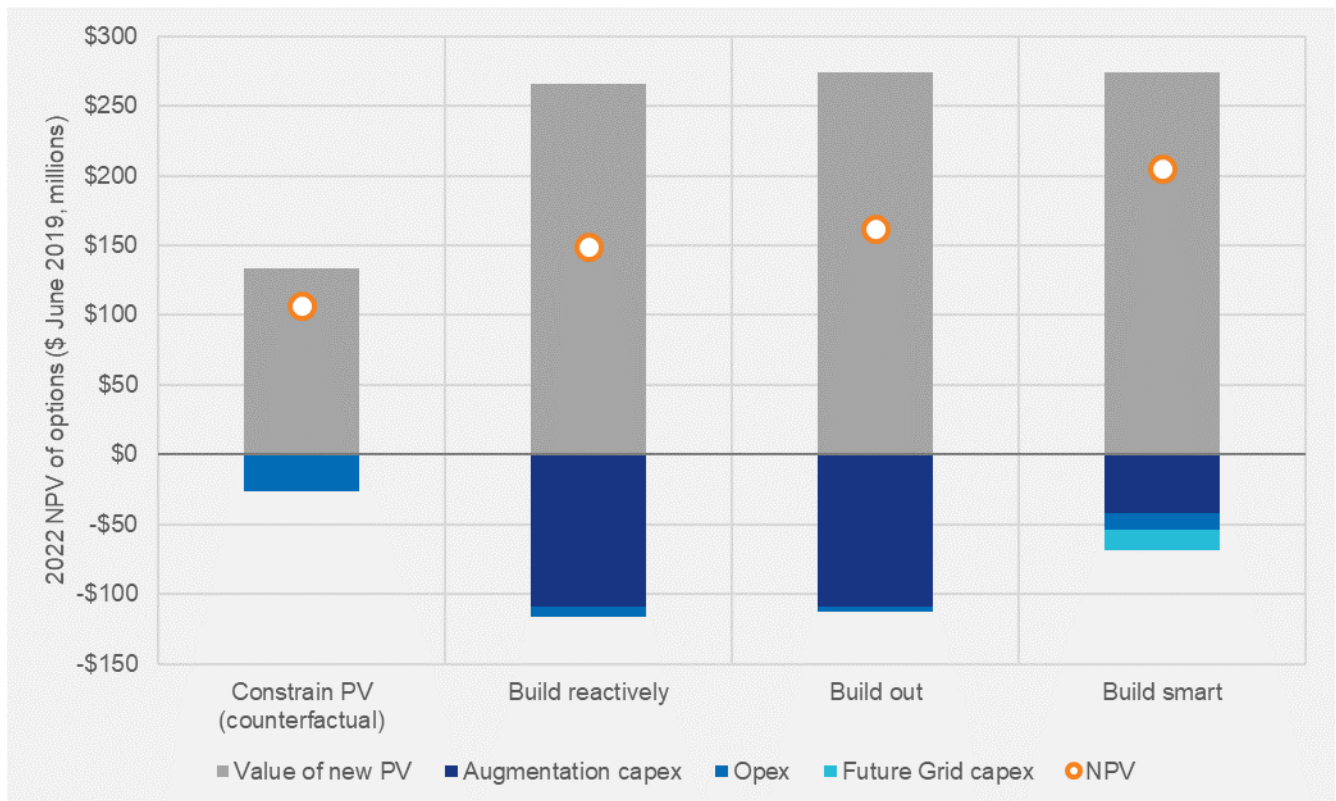
¹⁰⁷ We have used the Essential Services Commission's proposed minimum single rate feed-in tariff for 2020-21 of 10 c/kWh, as set out in the *Minimum electricity feed-in tariff to apply from 1 July 2020: Draft Decision*, 3 December 2019.

The three options we then considered against the counterfactual ('*Constrain DER*') were:

- *Build Reactively* – augmenting the network reactively (by installing larger capacity distribution transformers) after supply quality problems eventuate (with this generally manifesting as DER inverters tripping and distribution transformer fuses failing) based on the forecast increase in DER
- *Build Out* – augmenting the network proactively to provide the necessary hosting capacity for the forecast increase in DER
- *Build Smart* – investing in new technologies to improve LV network data availability, monitoring and modelling, allowing us to deploy an optimal mix of technical solutions to increase the hosting capacity of the network.

Each of these options would require different expenditures over the 20 year time horizon we considered, however, each would largely avoid the need to constrain DER exports during this time, therefore each providing a similar benefit to customers in the form of additional energy generated from solar PV systems when compared to the counterfactual. Figure 6–7 illustrates the results of the cost-benefit analysis of all options for enabling DER, showing that the Build Smart option provides the highest net benefit to customers of \$205M at 2022 (June 2019 dollars).

Figure 6–7: Enabling DER cost-benefit analysis (\$ June 2019, millions)



Our forecast expenditure incorporates activities under our Enabling DER initiative which represent the Building Smart option as the most efficient means of unlocking the future value of DER for our customers over the long-term. Through these activities, we will:

- develop an LV Network Model – improve data capture processes to capture DER information, implement LV network modelling tools, trial LV network monitoring and implement new DER assessment functionality as part of our website and connection portal

- enable dynamic DER export control – install LV network monitoring devices to enable dynamic export limits and enable new Distribution Management System modules in our SCADA system to allow for the control and management of DER
- increase DER hosting capacity – augment distribution substations and LV circuits to increase LV network hosting capacity and install LV voltage regulation devices to mitigate power quality impacts from increased DER.

In addition to providing a net economic benefit to customers over the long-term, this initiative is critical in enabling us to efficiently meet our customers' expectations that we accommodate greater DER penetration in the future (a recommendation from our People's Panel) and avoid the need to constrain DER exports. Furthermore, our proposed investments in this initiative respond prudently to uncertainty around how future customer and market scenarios may eventuate by laying the necessary 'no regret' foundations outlined by the Energy Networks Australia and CSIRO's Electricity Network Transformation Roadmap and Australian Energy Market Operator (AEMO) and Energy Networks Australia's Open Energy Networks programs. Our proposed activities under this initiative are also broadly consistent with those recently proposed by other DNSPs, such as SA Power Networks.

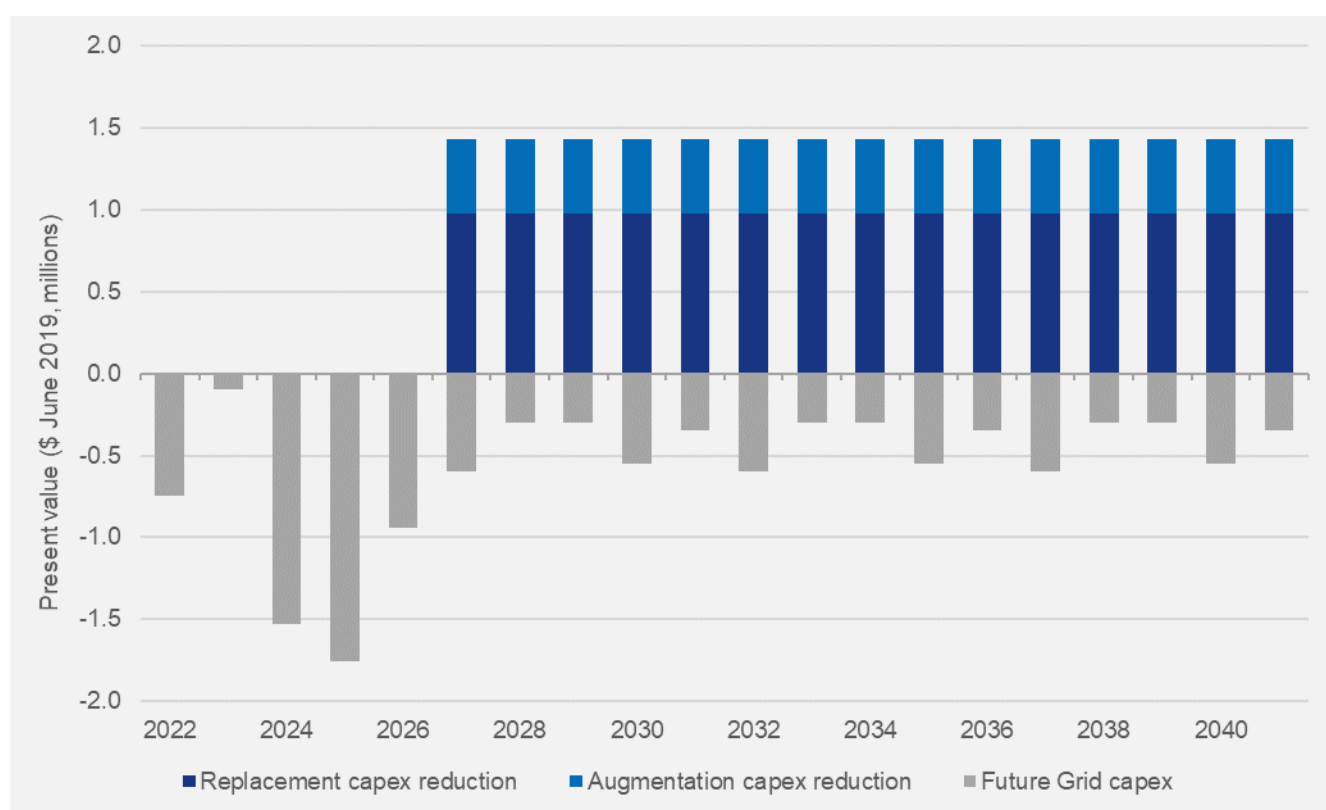
The capital expenditure associated with these activities is shown in Table 6–8. For further information on the activities which form part of our forecast, refer to our Future Grid investment proposal.

Table 6–8: Proposed capital expenditure for Future Grid program – Enabling DER initiative (\$ June 2021, millions)

Activity	Expenditure category	FY22	FY23	FY24	FY25	FY26	Total
LV Network Model	Non-network IT	2.5	1.1	1.2	1.2	0.2	6.1
Increase DER Hosting	Augmentation	1.1	1.4	1.7	2.0	2.1	8.4
Dynamic DER Export	Non-network IT	0.3	0.5	3.3	1.4	1.1	6.6
Dynamic DER Export	Augmentation	0.5	0.5	0.5	0.5	0.5	2.4
Enabling DER initiative total capital expenditure		4.4	3.5	6.6	5.0	4.0	23.6
	Augmentation	1.6	1.9	2.2	2.5	2.6	10.8
	Non-network IT	2.8	1.6	4.4	2.5	1.4	12.7

Optimised Asset Investment

We also propose to undertake a second, smaller, initiative that will allow us to utilise existing network assets better and further optimise future investment decisions over the long-term as our assets approach the end of their lives or become capacity-constrained. These activities will leverage developments in available network monitoring technology and new asset lifecycle planning and rating approaches, and we expect them to enable a reduction in annual replacement and augmentation capital expenditure by 3 per cent over the period FY27 to FY41. Figure 6–8 shows the cost-benefit analysis for our proposed expenditures under the Optimised Asset Investment initiative, with our investment over the FY22-26 resulting in a positive net benefit to customers of \$9M (real June 2019 dollars) over 20 years.

Figure 6–8: Cost-benefit analysis for Optimised Asset Investment initiative (\$ June 2019, millions)

Through the activities under our Optimised Asset Investment initiative, we will:

- further mature our condition monitoring capabilities – install real-time condition monitoring equipment on zone substation assets approaching their end of life and deploy a condition monitoring equipment software package for use in our asset management system
- deliver dynamic network rating capability – install real-time climate and asset monitoring equipment, deploy software to calculate real-time dynamic network asset ratings and modify our Operational Technology systems to take account of dynamic network ratings
- improve our integrated asset investment frameworks – integrate holistic lifecycle management software into all asset management processes, providing a better understanding of asset risks and therefore enhancing decision making processes for asset replacements
- develop an integrated network design tool – develop and deploy an integrated tool covering multiple stages of the network design process, allowing for increased efficiency in network augmentation and design tasks across the network.

In developing these activities, we considered an alternative option of not undertaking them. While this would result in lower expenditure in the short-term, doing so would not enable the realisation of additional benefits in the future, and over the long-term would result in a smaller net benefit to customers. Additionally, our proposed initiative responds to the feedback we received during our consultation processes,¹⁰⁸ through which customers expressed a strong interest in us investing in new technologies in the near term to put downward pressure on prices in the future.

The capital expenditure associated with this initiative is shown in Table 6–9. For further information on the activities which form part of our forecast, refer to our Future Grid investment proposal (Attachment 05-04).

¹⁰⁸ Including recommendation number 6 of our People's Panel.

Table 6–9: Proposed capital expenditure for Future Grid program – Optimised Asset Investment initiative (\$ June 2021, millions)

Activity	Expenditure category	FY22	FY23	FY24	FY25	FY26	Total
Condition Monitoring	Non-network IT	0.0	0.1	0.1	0.0	0.0	0.2
Condition Monitoring	Augmentation	0.1	0.0	0.1	0.1	0.0	0.4
Integrated Design	Non-network IT	0.6	0.0	0.0	0.0	0.0	0.6
Integrated Asset Investments	Non-network IT	0.0	0.0	0.6	0.6	0.0	1.3
Dynamic Network Ratings	Augmentation	0.0	0.0	0.5	0.5	0.5	1.6
Dynamic Network Ratings	Non-network IT	0.0	0.0	0.1	0.4	0.3	0.8
Optimised Asset Investment initiative total capital expenditure		0.8	0.1	1.5	1.7	0.9	4.9
	Augmentation	0.1	0.0	0.7	0.7	0.5	2.0
	Non-network IT	0.6	0.1	0.8	1.0	0.3	2.9

6.3.1.3 Distribution substation augmentation (power quality-driven)

Our forecast includes expenditure for the augmentation of distribution substations in response to issues other than plant ratings being exceeded due to load growth. This expenditure is predominately targeted at ensuring our network can maintain compliance with quality of supply measures set out in the Victorian Electricity Distribution Code.¹⁰⁹ Power quality issues are generally a result of elevated network impedance, particularly in relation to long LV circuits. However, these issues can be magnified by the installation of small-scale DER which further raise network steady-state voltages.

In addition to non-compliance with the Electricity Distribution Code, deterioration in network quality of supply can also negatively impact the operation and lifespan of customer equipment—for example, low voltage on the network can cause electric motors in customer equipment such as air conditioners to fail. Poor power quality has consistently been highlighted as a concern by our larger commercial and industrial customers through our engagement with them, given the potential for them to incur significant financial losses through damage to manufacturing equipment or lost production time.

Our expenditure under this program is forecast to increase during the next regulatory period in response to continued strong growth in the amount of DER customers are expected to connect to our LV network. Our Future Grid program (outlined in section 6.3.1.2) is primarily targeted at addressing the network challenges posed by growing DER penetration, specifically high voltages at customer connection points on the LV network which cause DER equipment to trip. However, we must also address a range of other network power quality issues (some of which are attributable to DER, but some of which are attributable to industrial customer loads), such as lower voltages, harmonics and flicker. These other power quality issues are the focus of our power quality distribution substation augmentation program. This program is therefore mutually exclusive from our Future Grid program, and the expenditure on distribution substation augmentation included as part of our forecast capital expenditure will be necessary regardless of the activities undertaken under Future Grid program.

6.3.1.4 Other projects

Our forecast also contains two minor augmentation projects which are not demand-driven:

- installation of oil containment devices at Braybrook zone substation – we have adopted a risk-based approach to progressively install fully sealed oil containment bunds to mitigate environmental risks associated with zone substation transformer oil leakage and spills

¹⁰⁹ Electricity Distribution Code, s. 4.

- installation of a voltage regulator on a feeder in the Sunbury supply area – this minor project will address specific power quality issues identified on this feeder.

6.4 References

Supporting documents included as part of our regulatory proposal or response to the Reset RIN for our forecast augmentation capital expenditure are listed below.

Document title	Location
Attachment 05-03 ACIL Allen Electricity demand forecast report	Regulatory proposal
Attachment 05-04 Future Grid investment proposal	Regulatory proposal
Attachment 05-06 WSP REFCL joint planning report	Regulatory proposal
Attachment 06-05 Operating expenditure step changes	Regulatory proposal
JEN Internal Demand Forecast Report 2019	RIN Response
JEN PR0507 Internal Load Demand Forecast Procedure	RIN Response
2019 Distribution Annual Planning Report	RIN Response
JEN network augmentation planning criteria paper	RIN Response
Demand Management Options Analysis report	RIN Response
Distribution Feeders Network Development Strategy	RIN Response
Customer Initiated Capital Summary Report ¹¹⁰	RIN Response
BTS-NS Subtransmission Network Development Strategy	RIN Response
Preston Area Network Development Strategy	RIN Response
Distribution Asset Class Strategy	RIN Response
Primary Plant Asset Class Strategy	RIN Response
Network Performance Plan	RIN Response
CN Switchgear Replacement Business Case	RIN Response

¹¹⁰ Contains the Fairfield/Alphington Network Development Strategy.

7. Non-network expenditure

7.1 Summary

Non-network capital expenditure relates to the assets that are used to support the operation of our network and delivery of standard control services to customers. Non-network expenditure is grouped into four categories in the AER's RINs:

- information and communications technology (**ICT**) and equipment¹¹¹
- motor vehicles
- property
- other (including tools, plant and other equipment).

Our non-network expenditure objectives:

- Meet customers' expectations that we should maintain our current levels of service reliability (including the frequency and length of network outages) at the most efficient cost over the long-term
- Manage safety, environmental, physical security and cybersecurity risks to as low as practicable and comply with all applicable regulatory obligations at the most efficient cost over the long term
- Efficiently minimise any constraints on grid exports from distributed energy resources to the extent possible

Our capital expenditure forecast for the next regulatory period comprises \$114M of non-network expenditure. This represents a 26 per cent decrease in non-network expenditure from the current regulatory period.

The key drivers of our non-network expenditure in the forecast period are:

- new electricity market compliance obligations, particularly those relating to the five-minute and global settlement rule changes
- the need to continue the replacement of IT infrastructure and applications reaching the end of their useful lives—including through our like-for-like ('base') recurrent expenditure which is lower than our actual recurrent expenditure during the current regulatory period
- delivery of some new IT systems as enablers of our Future Grid program and to improve the way we provide information and communication channels to customers
- protecting our IT systems in response to growing cybersecurity threats
- the replacement of motor vehicles and other minor assets as they reach the end of their useful lives, including addressing a backlog of overdue vehicle replacements early in the next regulatory period, followed by a return to normal levels of motor vehicle expenditure.

Our non-network expenditure is shown on Figure 7–1. This illustrates a material decrease in our proposed total non-network capital expenditure from the current regulatory period—the primary drivers being an 18 per cent decrease in our IT capital expenditure and a 93 per cent decrease in our buildings and property expenditure. Our forecast is set out in Table 7–1.

¹¹¹ Referred to as 'IT & communications.'

Figure 7–1: Non-network expenditure (\$ June 2021, millions)

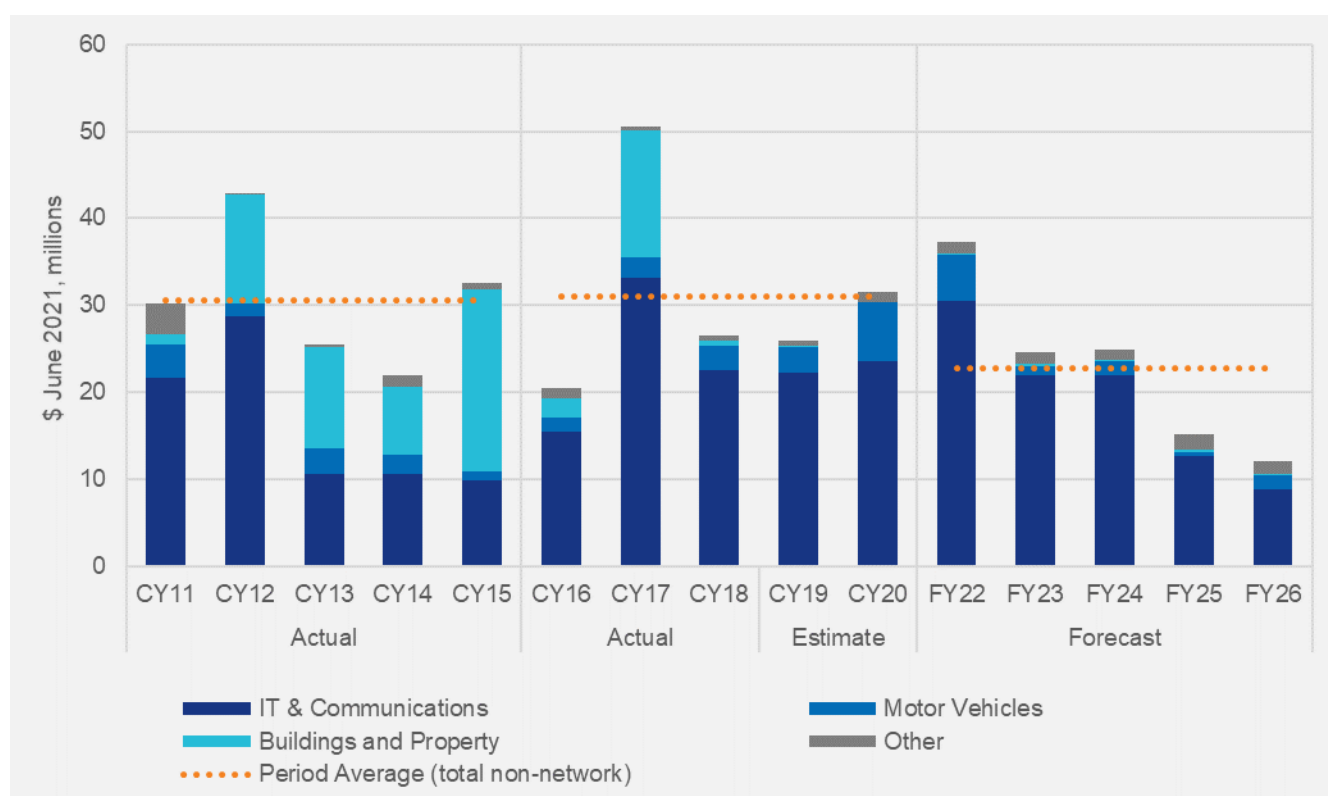


Table 7–1: Forecast non-network expenditure (\$ June 2021, millions)

Non-network expenditure type	FY22	FY23	FY24	FY25	FY26	Total
IT & communications	30.5	21.9	21.9	12.7	8.8	95.7
Motor vehicles	5.2	1.1	1.7	0.4	1.6	9.9
Buildings and property	0.2	0.3	0.2	0.4	0.2	1.3
Other	1.3	1.3	1.2	1.8	1.4	7.0
Total	37.3	24.5	24.9	15.2	12.0	113.9

7.2 IT & communications

IT and communications is the largest category within non-network capital expenditure, accounting for 84 per cent of JEN's non-network expenditure forecast. IT assets play a critical role in supporting the efficient delivery of SCS¹¹² to customers, and their importance continues to grow as the digitisation of the broader economy accelerates. Our IT assets provide platforms which support a wide range of activities for our customers:

- facilitating the real-time monitoring and control of the electricity network¹¹³

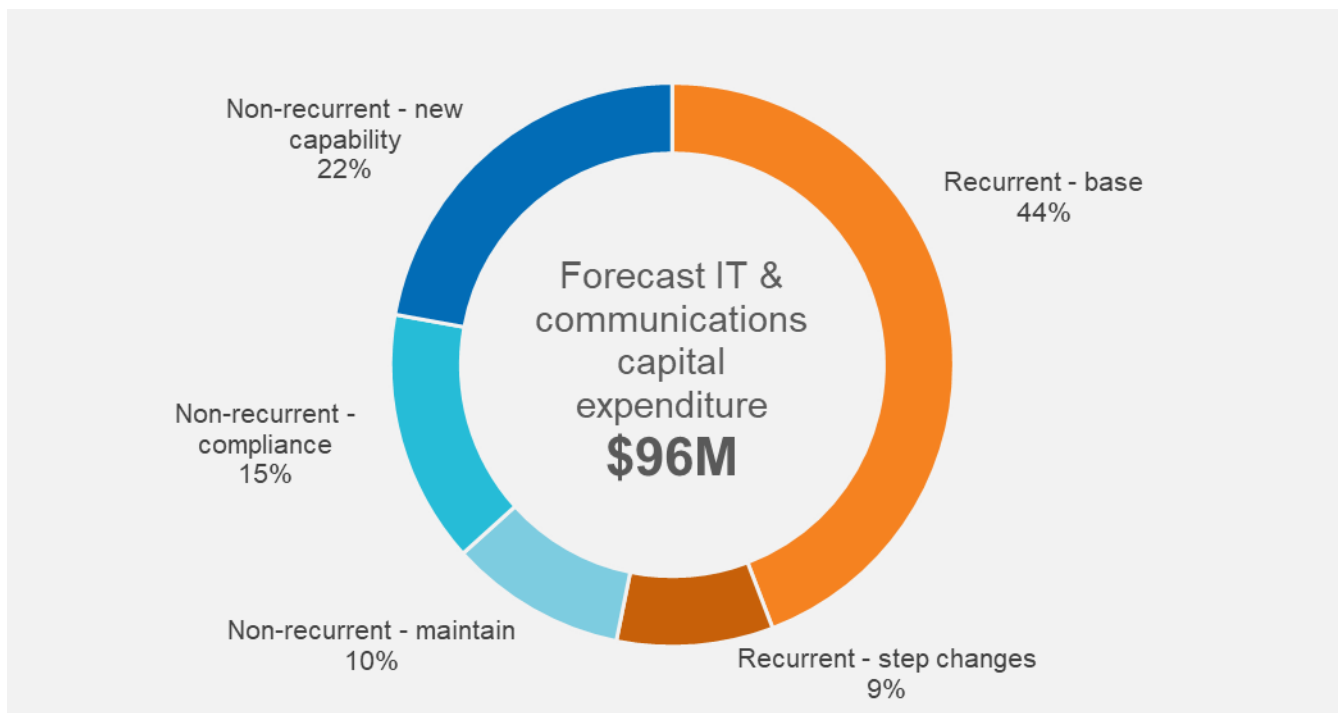
¹¹² Many of the IT systems used by JEN to support the delivery of SCS also support the delivery of alternative control services by JEN, as well as regulated and unregulated services by other entities within the Jemena group. Where systems are shared between multiple entities in the Jemena group, we allocate the costs of these systems in accordance with Group's accounting policies. Where systems are shared between multiple JEN services, we allocate costs in accordance with the JEN CAM.

¹¹³ Consistent with the definitions provided in the AER's RIN for the 2021-25 regulatory control period, Jemena has reported IT expenditure relating to SCADA and network control but which resides on the corporate office side of gateway devices under the 'non-network expenditure' category. SCADA and network control expenditure which relates to assets located on the network side of gateway devices has been reported under the 'replacement expenditure' category.

- interacting with customers and other market participants, including receiving service requests and facilitating billing
- planning and management of field operations, including for construction, maintenance and outages
- recording, reporting and analysis of asset and geospatial information, including for asset management planning
- general corporate support activities for our operations, including finance, reporting, human resources and procurement.

Our capital expenditure forecast for the next regulatory period comprises \$96M of IT and communications expenditure. This represents a 18 per cent decrease in IT and communications expenditure from the current regulatory period. Throughout this section, we have presented our forecast using the categories set out by the AER in its *Non-network ICT capex assessment approach*,¹¹⁴ with the composition of our forecast illustrated in Figure 7–2. Table 7–2 sets out our forecast capital expenditure, while longer-term trends in our IT and communications expenditure are shown in Figure 7–3.

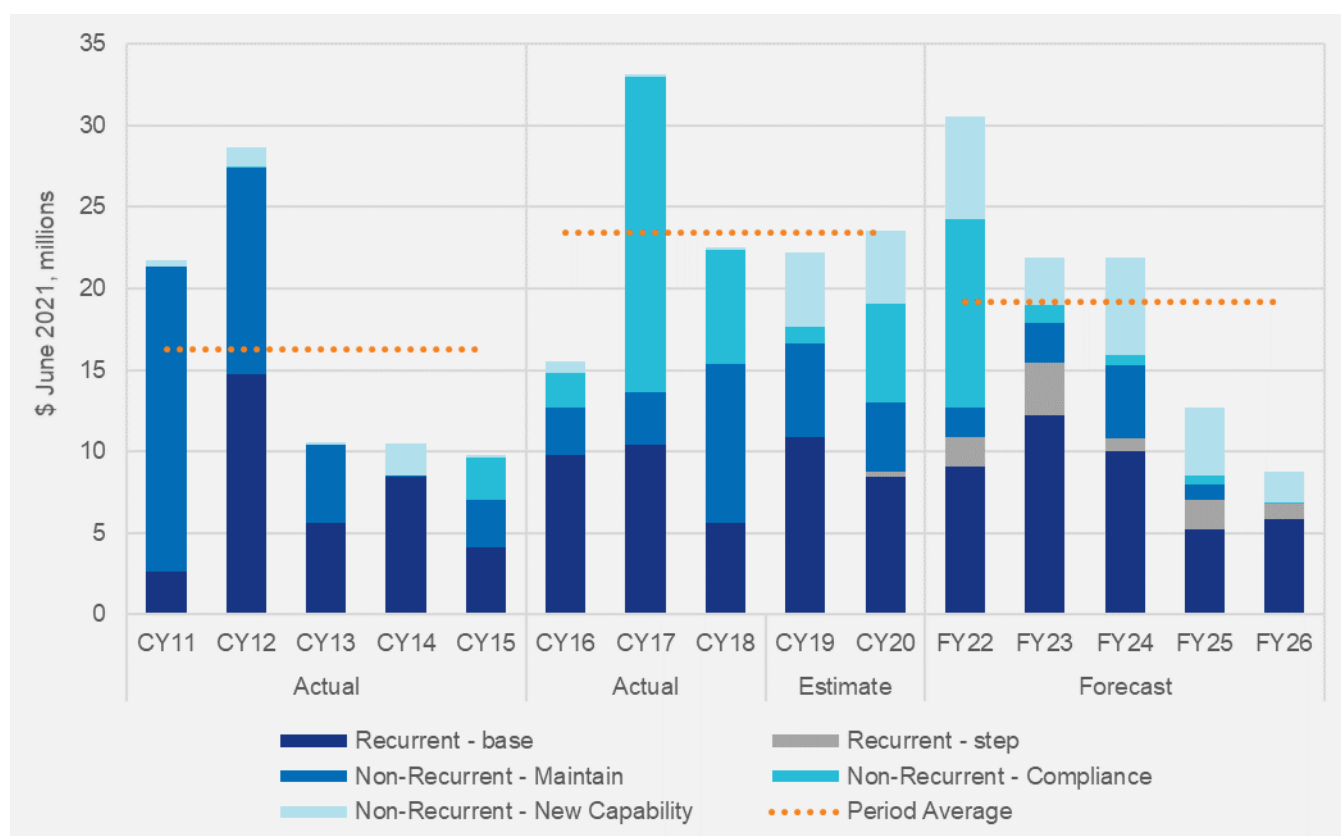
Figure 7–2: Per cent of forecast non-network IT & communications capital expenditure by category



¹¹⁴ AER, *Non-network ICT capex assessment approach*, November 2019.

Table 7-2: Forecast non-network IT & communications expenditure by assessment category (\$ June 2021, millions)

	FY22	FY23	FY24	FY25	FY26	Total
Recurrent – base	9.1	12.2	10.0	5.2	5.9	42.3
Recurrent step change – SCADA DMS-OMS	1.2	1.7	0.3	0.7	0.3	4.2
Recurrent step change – Data Warehouse & Business Intelligence	0.0	1.0	0.0	0.5	0.0	1.6
Recurrent step change – Mobility	0.6	0.6	0.4	0.6	0.6	2.8
Total recurrent	10.9	15.5	10.8	7.0	6.8	50.9
Non-recurrent – maintain	1.8	2.4	4.5	0.9	0.0	9.7
Non-recurrent – compliance	11.5	1.1	0.6	0.6	0.1	13.9
Non-recurrent – new capability	6.3	2.9	5.9	4.2	1.9	21.2
Total non-recurrent	19.6	6.4	11.1	5.7	2.0	44.8
Total IT & communications expenditure	30.5	21.9	21.9	12.7	8.8	95.7

Figure 7-3: IT & communications expenditure (\$ June 2021, millions)

7.2.1 Overview

Our proposed capital expenditure for the forecast period builds on a strong and stable foundational IT landscape which we have developed during the previous and current regulatory periods. Our focus during this time was on building a sustainable platform for the longer-term operations of our business, including by streamlining and consolidating systems where efficient to leverage scale and enterprise capabilities, reduce future costs and minimise risks.

Leveraging a solid foundation for our future IT environment

Examples of key projects we've undertaken since 2011 to streamline our IT environment include:

- replacing our core IT infrastructure (including several end-of-life systems) with more efficient and more cost-effective new technologies, such as infrastructure virtualisation and adopting some cloud-based services. This program has allowed for significant reductions in the footprints of primary and secondary data centre spaces and will lower future replacement costs for some hardware and software
- consolidating several systems during the previous regulatory period, or implementing standard solutions on an enterprise-wide basis. This facilitates improved procurement outcomes, the reuse of project delivery knowledge and reduces the diversity and cost of support skills required.

Our forecast reflects a balanced approach to investing in and leveraging our solid IT platform to efficiently meet the evolving needs of the energy market and our customers, with our IT objectives reflecting our customers' stated priorities and our broader capital expenditure forecast objectives outlined in section 1.4:

- **maintaining the safety, quality, reliability and security of services** – in line with what our customers have told us, we plan to maintain all necessary IT systems to ensure their optimal lifecycle is achieved and that they continue to support us in delivering safe, reliable and efficient distribution services over the long-term. In particular, over the next regulatory period, we will strengthen our focus on cybersecurity and resilience, including the continued protection of privacy and data integrity
- **complying with new regulatory obligations** – we must conform to new or changed legalisation or other regulatory instruments and plan to remain compliant at all times throughout the next regulatory period
- **planning for the future** – recognising that the needs of our customers continue to change, we must ensure our IT systems are capable of supporting growth and that they include flexibility to support changes to business or customer requirements without the need for replacement or major rework. We will also respond to customer feedback that we should improve our online and mobile customer services and channels, and customer outage communications, and will invest in some IT systems as part of our Future Grid program.

We developed our forecast program on a bottom-up basis and took into account:

- the condition, performance and risks of our current IT environment and assets, and how these factors are expected to change over the forecast period
- customer expectations and preferences, including specific recommendations of our People's Panel
- compliance obligations
- business requirements
- historical IT project delivery costs
- the emergence of new technologies

- interdependencies with other parts of JEN's expenditure forecasts (IT is a direct enabler of some of our proposed network capital expenditure, for example in our Future Grid program)
- the potential to employ efficient capital-operating expenditure trade-offs, for example, cloud-based computing.

Our IT project cost estimation methodology is described in our RIN Response – *Technology Plan*. Our top-down methodology used to estimate the majority of our individual project costs¹¹⁵ is consistent with the approach applied by JGN to develop its forecast IT capital expenditure for its 2020-25 Access Arrangement Proposal, which the AER found to be a reasonable approach.¹¹⁶ In developing our expenditure forecast to deliver on our expenditure objectives, we consider each customer, market and business requirement on a case-by-case basis to determine the most efficient way of meeting the identified need, given there will often be multiple options to do so.

Our forecast IT and communication capital expenditure is explained by category in the sections below.

7.2.2 Recurrent expenditure

Consistent with the AER's guidance,¹¹⁷ our recurrent expenditure relates to maintaining existing services, functionalities, capability and market benefits, and occurs at least once every five years. We have further categorised our recurrent expenditure forecast into two categories:

- **base recurrent expenditure**—expenditure relating to systems which have been in place for the entirety of the current regulatory period, enabling comparisons like-for-like comparisons in recurrent expenditure between periods
- **step changes in recurrent expenditure**—recurrent expenditure which we expect to incur in the next (and subsequent) regulatory periods but which we did not incur during the current regulatory period, as it relates to systems (or major parts thereof) which were first implemented during the current regulatory period.

We have developed our forecast recurrent expenditure to allow us to broadly maintain our existing IT systems which will, therefore, enable us to maintain our current service levels to our customers throughout the next regulatory period. As with network replacement capital expenditure, age isn't the single determining factor in system lifecycle replacement planning. We aim to optimise replacement timing based on the condition, performance, risks and ongoing serviceability of every asset. Our IT lifecycle expenditure forecast includes the replacement of assets where:

- it is no longer economic to keep an asset compared to replacing it with a new one because maintenance costs will increase once it is deemed to be an aged asset for vendor support purposes
- where a system is critical and the vendor no longer supports the product because it is too old to maintain the product using scarce resources, it may represent an unacceptable risk to JEN's ongoing delivery of services to continue operating that asset¹¹⁸
- the asset can no longer expand or extend to meet business growth and usage demand
- the asset is no longer compatible with other newer technologies within our IT environment (such as operating systems, hardware or networking)
- the security of the service or product cannot be assured, and it presents a potential entry point or exposure to a cybersecurity breach.

¹¹⁵ We have developed bottom-up cost estimates for some IT and communications projects within our Five-Minute Settlement and Global Settlement and Future Grid programs.

¹¹⁶ AER, *Draft Decision, Jemena Gas Networks (NSW) Ltd Access Arrangement 2020 to 2025, Attachment 5 Capital expenditure*, November 2019, p. 5-39.

¹¹⁷ AER, *Non-network ICT capex assessment approach*, November 2019.

¹¹⁸ A lack of available support for a product may represent a risk in terms of impacting the continuity of our operations, but also as it may limit our ability to make changes to a system in response to external requirements, such as new regulatory obligations (as making changes to a system when support is unavailable will generally be highly risky).

The sections below explain our forecast recurrent base and step change expenditure in further detail.

7.2.2.1 Base recurrent expenditure

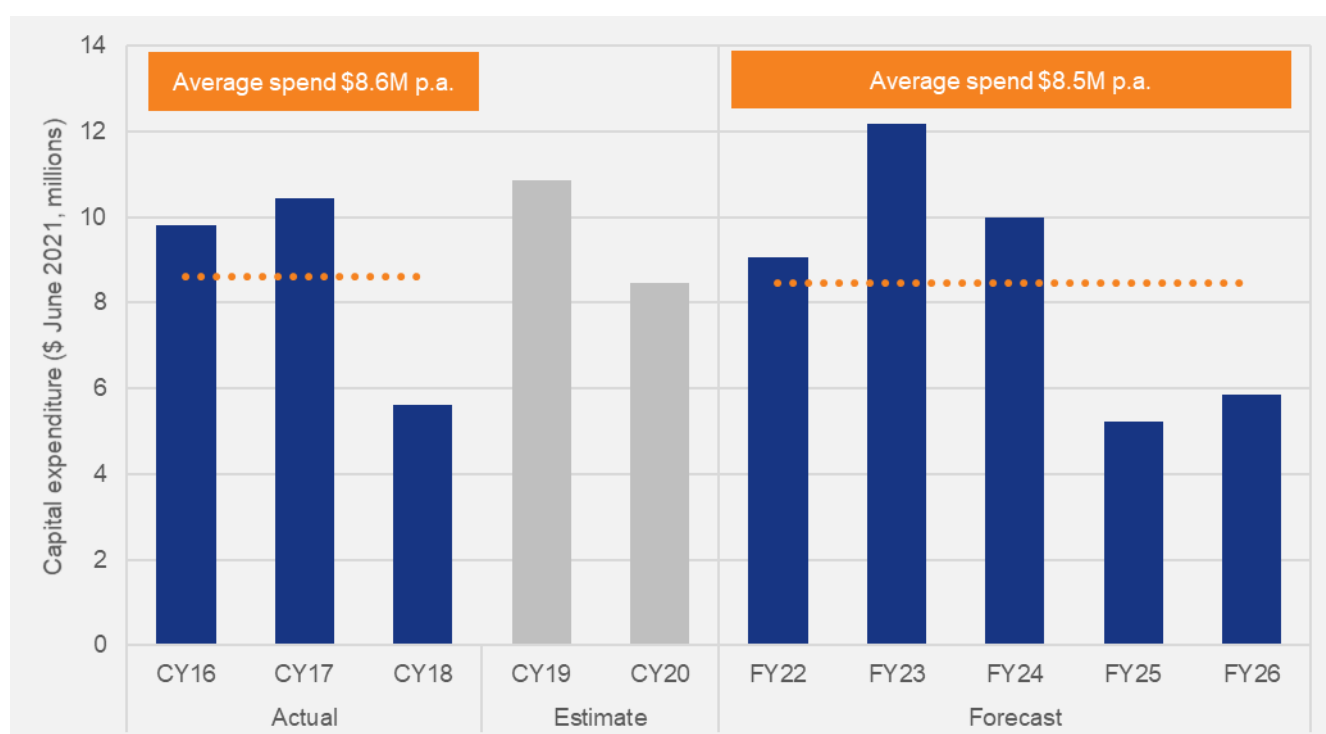
Our forecast recurrent base expenditure for the next regulatory period is \$8.5M on average per annum, which is 1.8 per cent lower than our equivalent spend during the current regulatory period. Importantly, our forecast base recurrent expenditure does not include expenditure relating to the recurrent life-cycling and upkeep of three new or significantly expanded systems which we implemented during the current regulatory period, with these discussed in section 7.2.2.2.

Our recurrent base expenditure is shown in Figure 7–4. We note that the AER’s assessment approach outlines a preferred approach of using a five-year rolling average when undertaking trend analysis on historical recurrent expenditure, given individual expenditures may occur on different cycles and lead to lumpy recurrent expenditure year-on-year. We broadly agree with the need to interpret trend analysis with caution due to the potential for it to be affected by outlier data. For this reason, we consider an appropriate ‘baseline’ for use in trend analysis of our recurrent expenditures to be the three years CY16 to CY18. Although this is a shorter period than the AER’s suggested five-year rolling average, we consider that our recurrent expenditures for CY14 and CY15 do not reasonably reflect a level of recurrent expenditure which JEN would expect in the future, because:

- JEN undertook a large amount of non-recurrent expenditure in CY11 and CY12 to implement a new enterprise resource planning system and also undertook major data centre relocations, meaning that these systems required significantly less recurrent spend in the five years following their initial implementation to maintain their required levels of performance
- changes to the classification (in CY16) of AMI services, which were previously regulated under a Victorian Order in Council. The transfer of AMI services to regulation under the NER provided an opportunity for JEN to reallocate the costs of several IT systems to be shared between AMI (alternative control services) and SCS going forward, reflecting the fact that these systems are also used in the provision of SCS. The scope of systems supported by SCS recurrent expenditure between the CY11-15 and CY16-20 regulatory periods is different, and therefore, these figures are not comparable.

We also have not used our estimated expenditure in CY19 and CY20 to inform a view of ‘baseline’ expenditure for the current regulatory period, as our expenditure for these years is estimated, and we note the AER refers to ‘historic data’ for trend analysis in its assessment approach. We consider this is a balanced approach given our estimated recurrent expenditure in CY19 and CY20 is slightly higher than our baseline over CY16 to CY18.

Figure 7–4: Base recurrent expenditure (\$ June 2021, millions)



Benchmarking of recurrent expenditure

Consistent with the approach outlined by the AER, we have undertaken high-level partial performance indicator (PPI) benchmarking of our historical recurrent expenditure,¹¹⁹ comparing JEN against other DNSPs using data collected through the Category Analysis RINs and using the methodology outlined in the AER's *Non-network ICT capex assessment approach*.¹²⁰ To undertake this analysis, we summed each DNSP's recurrent capital expenditure, client device capital expenditure and total non-network IT operating expenditure, and divided these annual figures by customer numbers. Taking the average of the PPI results over the 2016-18 reporting years, JEN was ranked mid-pack (7th of 13) on expenditure per customer. However, as highlighted in our submissions¹²¹ during the consultation process for the AER's *Non-network ICT capex assessment approach*, we note the considerable variance in year-on-year results and between different DNSPs.

Additionally, we reiterate our concerns that this analysis is based on data which is reported as estimated by some DNSPs—that is, its presentation may be materially contingent upon judgement or methods for which there are equally valid alternatives. We do, however, note that the AER does not intend to use benchmarking analysis deterministically.¹²²

7.2.2.2 Step changes in recurrent expenditure

To reflect increases which we expect to incur in our future recurrent expenditures, we have identified three step changes. The AER's ICT assessment approach notes that there may be legitimate reasons for increases in recurrent IT capital expenditure over time:¹²³

For example, additional recurrent ICT expenditures may be required after the implementation of non-recurrent projects to maintain that new service or functionality. In such cases, the distributor must be

¹¹⁹ Our recurrent expenditure for the years examined does not include any step changes.

¹²⁰ AER, *Non-network ICT capex assessment approach*, November 2019.

¹²¹ Jemena, ICT Expenditure Assessment, 19 June 2019; and Jemena, Re: Response to the AER's consultation on the ICT expenditure assessment guideline, 2 October 2019.

¹²² AER, *Non-network ICT capex assessment approach*, November 2019, p. 16.

¹²³ AER, *Non-network ICT capex assessment approach*, November 2019, p. 10.

able to provide evidence to explain the need for this forecast variation in expenditure from historical trend.

During the current regulatory period, we undertook non-recurrent projects to expand our technology capability through three major system implementations—SCADA DMS-OMS, Data Warehousing & Business Intelligence and Mobility.¹²⁴ Each of these systems will require additional recurrent expenditure for the first time during the next regulatory period to maintain their functionality, and we have outlined the basis for each of these step changes in Table 7–3. In line with other expenditure in our *Recurrent – base* category, the expenditure reflected in these step changes will allow us to maintain these three systems within an efficient level of risk by undertaking lifecycle upgrades on the applications and necessary hardware. Refer to the respective step change investment briefs provided in our RIN Response for further information.

Table 7–3: Step changes in recurrent expenditure

Recurrent step change	Description
SCADA DMS-OMS	<p>Our Distribution Management System (DMS) and Outage Management System (OMS) is critical to the control and monitoring of our distribution network. During the current regulatory period, we implemented new foundation platforms for our DMS-OMS. Due to the large size and complexity of this implementation, our lifecycle maintenance expenditure relating to this system (and the hardware it runs on) was constrained during the current regulatory period.</p> <p>As such, our base recurrent expenditure does not capture the ongoing lifecycle maintenance activities necessary for these critical systems. We have therefore forecast a step change to our recurrent expenditure to reflect that these lifecycle activities and expenditures will be required in the next regulatory period.</p>
Data Warehousing & Business Intelligence	<p>Our Data Warehouse and Business Intelligence systems are used to extract information from a range of systems across our business into a data warehouse, where analysis tools are used to produce our financial, management and regulatory (including RIN) reporting. During the current regulatory period, we implemented a new foundation platform consisting of new products¹²⁵ and dedicated reports.</p> <p>As this system represents a newly expanded capability introduced in the current regulatory period, our recurrent expenditure for the current regulatory period does not reflect any expenditure which will be necessary to maintain the performance of this system during the next regulatory period. We have therefore forecast a step change to recurrent expenditure for the next regulatory period.</p>
Mobility	<p>Our mobility system provides field crews with direct access to asset information such as location, status and condition, helping to improve the safety of staff and customers during field operations and improve the quality and timeliness of asset information recorded in our systems. During the current regulatory period, we undertook a significant first step of developing a foundational platform for mobility, implementing new systems and deploying new communications mechanisms and mobile devices to allow field crews to access JEN's core application systems when on-site and to both view and update information in real time.</p> <p>As this is a new system for JEN, our current regulatory period's recurrent expenditure does not reflect the activities which will be required to maintain the operation and functionality of this system throughout the next regulatory period. We have therefore included a step change which reflects this necessary incremental expenditure.</p>

7.2.3 Non-recurrent expenditure

Within our forecast of non-recurrent expenditure, we have applied three sub-categories consistent with the AER's approach¹²⁶—maintaining systems, compliance and new capability. Trends in non-recurrent expenditure over time

¹²⁴ These three programs formed part of our forecast capital expenditure for the current regulatory period, which was accepted by the AER in its final determination.

¹²⁵ We implemented the SAP HANA database product as part of this solution, however this is unrelated to our SAP Enterprise Resource Planning system and any potential future migration to the SAP S4/HANA platform.

¹²⁶ AER, *Non-network ICT capex assessment approach*, November 2019, s 2.1.

are generally less useful to examine than recurrent expenditure, as the drivers for and magnitude of different non-recurrent projects will vary considerably from one regulatory period to the next due to a wide range of factors. We discuss each subcategory below, and an overview of the key projects within each category is provided in Table 7–4.

Maintaining systems

This subcategory reflects expenditure relating to maintaining existing services, functionalities, capabilities or market benefits that occur over cycles greater than five years. While many IT systems have technical lives which drive upgrade cycles of five years or less, some critical systems—such as enterprise resource planning or outage management systems—have upgrade cycles which are longer than this. The drivers and objectives of non-recurrent maintenance expenditure are similar to those of recurrent maintenance expenditure, discussed in section 7.2.2—this expenditure is targeted at keeping our systems stable and secure to underpin the continued safe and efficient delivery of services to customers.

Our non-recurrent maintenance expenditure primarily relates to undertaking major version upgrades necessary to ensure hardware or software remains within vendor support windows—as vendor support for business- or market-critical systems is usually essential to maintain an acceptable level of system availability and cybersecurity risk.¹²⁷ As it relates only to maintaining existing systems, expenditure in this subcategory is considered as risk-driven, and would generally not be expected to produce additional benefits (such as operational efficiencies) for consumers.

Compliance

Expenditure in our compliance subcategory is driven by evolving energy market regulations and frameworks which often require us to make changes to our market-facing IT systems to align with new market protocols, procedures and standards. Additionally, we have included expenditure to uplift our cybersecurity maturity in this category as we are undertaking this expenditure in line with the recommendations of the Australian Energy Sector Cyber Security Framework (**AESCSF**)¹²⁸ and it has similar characteristics to compliance expenditure.

New capability

This subcategory of expenditure reflects investments in new or expanded IT capabilities or functionality. Drivers of this expenditure can vary considerably between projects, but may include expected future efficiency benefits (such as avoided or reduced future capital or operating expenditures), improvements in customer service and experience, or improvements in the safety or reliability of distribution services. In some cases, a major system upgrade or rebuild may be primarily driven by the need to maintain that existing system, but in addition to replacing the existing system we may concurrently invest in benefit-driven improvements to that system's capability. Consistent with the AER's approach,¹²⁹ we have classified expenditures separately between the *maintaining systems* and *new capability* subcategories.

7.2.3.1 Non-recurrent projects

Unless otherwise noted, all investment briefs and other supporting documents referred to in this table are provided as supporting materials in JEN's Reset RIN Response.

¹²⁷ Even where a system can operate safely without vendor support, exogenous factors such as the need to maintain its compatibility with other parts of our technology stack can drive the need for recurrent upgrades—for example, an application may be stable by itself, but we may need to upgrade it to a newer version if the old operating system it requires to run becomes unsupported or poses a security risk.

¹²⁸ This framework was developed through the collaboration of industry and government stakeholders, including AEMO, the Australian Cyber Security Centre and the Critical Infrastructure Centre.

¹²⁹ AER, *Non-network ICT capex assessment approach*, November 2019, p. 9.

Table 7–4: Major non-recurrent projects

Project	Description		
SAP migration	<p>Jemena currently uses SAP's Enterprise Resource Planning (ERP) and Industry Specific – Utilities (ISU) modules for our core business functions, including finance, human resource management, payroll, works and asset management and billing. SAP has released a major upgrade (referred to as S/4) of its ERP and ISU platforms and announced that it would end its support of Jemena's current ECC6 versions in 2025. As we use these platforms for our core business processes, the unavailability of our SAP system for an extended period would result in JEN failing to comply with its Electricity Distribution Licence and various other electricity market obligations. As such, we consider that the continued operation of ECC6 platforms following the end of vendor support represents an unacceptable risk to the ongoing provision of network services to customers (and to the security of our technology environment and distribution network).</p> <p>Our strategic approach is to therefore ensure that we maintain vendor supported versions of the platforms we require to deliver these core business functions. In developing this strategic approach, we considered alternatives such as the use of third-party support beyond the vendor's declared end-of-life, however our assessment of these has determined that they do not meet the standard necessary to maintain the security of our systems. We also considered options including delaying upgrade, undertaking a full transformational system re-implementation (a significant investment which would remove the large number of outdated customisations inherent in our current systems) and moving to products from other vendors, such as Oracle and Microsoft.</p> <p>Our forecast includes capital expenditure to undertake a 'technical' upgrade of our ERP and ISU systems to the vendor-supported S/4 versions, allowing us to maintain the functionality, security and availability of these core business systems, and therefore maintain our current levels of service to customers. Our proposed approach involves retaining current system (and therefore business process) designs and migrating them to the new platforms—in contrast to previous SAP version upgrades where we have introduced new system functionality and redesigned business processes as part of the implementation project.</p> <p>Refer to our RIN Response – <i>IT Investment Brief - SAP Migration</i> and <i>IT Business Case - SAP Migration</i> for further information.</p> <table> <tr> <td>Forecast capital expenditure \$5.6M (Maintaining Systems)</td><td>Customer benefits Maintain the reliability of our services and manage cybersecurity risks.</td></tr> </table>	Forecast capital expenditure \$5.6M (Maintaining Systems)	Customer benefits Maintain the reliability of our services and manage cybersecurity risks.
Forecast capital expenditure \$5.6M (Maintaining Systems)	Customer benefits Maintain the reliability of our services and manage cybersecurity risks.		
System management	<p>This minor program will allow us to replace various system management tools, which we use to monitor and control the health of the software and hardware within our IT ecosystem. These tools are critical to the efficient management and operation of our IT infrastructure platforms, and vendor support is required to ensure they are able to be patched to maintain compatibility with other products in our IT ecosystem as it continues to evolve. The lifecycle of these tools is longer than five years, therefore we have included this project in the non-recurrent sub-category.</p> <p>Refer to our RIN Response – <i>IT Investment Brief - System Management</i> for further information.</p> <table> <tr> <td>Forecast capital expenditure \$0.5M (Maintaining Systems)</td><td>Customer benefits Maintain the reliability of our services and manage cybersecurity risks.</td></tr> </table>	Forecast capital expenditure \$0.5M (Maintaining Systems)	Customer benefits Maintain the reliability of our services and manage cybersecurity risks.
Forecast capital expenditure \$0.5M (Maintaining Systems)	Customer benefits Maintain the reliability of our services and manage cybersecurity risks.		

Project	Description		
Five-Minute Settlement and Global Settlement	<p>In November 2017, the Australian Energy Market Commission (AEMC) made a final rule to change the settlement period for the electricity spot price from thirty minutes to five minutes, aligning operational dispatch and financial settlement at five-minute intervals. The change takes place in stages and starts in 2021.¹³⁰ In addition to this change, in December 2018, the AEMC made a final rule that requires a move from a boundary load settlement to a global settlement framework for the demand side of the wholesale electricity market.¹³¹ To ensure we comply with these new requirements, we must make changes to our IT systems and associated business processes which relate to the provision of data to the wholesale electricity market for settlement. Given their similar context, and to ensure we comply with these new obligations as efficiently as possible, we are progressing changes for both the Five-Minute Settlement and Global Settlement as a single project.</p> <p>Our forecast includes capital expenditure to modify and augment systems to provide them with the ability to interpret and process five-minute data, uplift our IT infrastructure capacity to send, receive and store a higher number of transactions. We considered a number of options to determine the most efficient technical solution and investment timing that ensures we comply with these new obligations.</p> <p>Refer to our RIN Response – <i>IT Investment Brief - 5-Minute Settlement and IT Business Case - 5-Minute Settlement</i> for further information.</p> <table> <tr> <td>Forecast capital expenditure \$10.2M¹³² (Compliance)</td><td>Customer benefits Maintain compliance with regulatory obligations.</td></tr> </table>	Forecast capital expenditure \$10.2M ¹³² (Compliance)	Customer benefits Maintain compliance with regulatory obligations.
Forecast capital expenditure \$10.2M ¹³² (Compliance)	Customer benefits Maintain compliance with regulatory obligations.		
Cybersecurity	<p>Our forecast includes expenditure to strengthen the cybersecurity of various IT systems. We have included this within the compliance category given it has similar—exogenous—drivers to other compliance projects. The number of digital devices connected to our IT networks is growing rapidly, and traditional, manual business processes are increasingly becoming digitised. This, along with global growth in cyber-crime, is driving increases in both the likelihood and consequence of a successful cyber-attack on our systems. The potential implications of a successful cyber-attack on our systems could be wide ranging, and could include the malicious operation of automated electricity network devices (putting at risk public safety and continued supply to customers), the compromise of customer data or disruption to business processes and operations.</p> <p>To meet customers' expectations of a safe and reliable electricity supply and to meet regulatory guidance regarding cyber security, we are proposing to invest in systems to identify, protect, detect, respond and recover from cyber-attacks. In 2019 the AESCSF was updated,¹³³ which provides a best practice cybersecurity guide for energy market participants. As part of this framework, AEMO recommends certain target state maturity levels based on a criticality assessment of each market participant. Consistent with the results of JEN's assessment under the framework's Criticality Assessment Tool, we are proposing to implement cybersecurity measures which are in line with the Security Profile (SP) 2 level. This will require non-recurrent investments in new capabilities to ensure our cyber defences are upgraded to combat increased sophistication of cyber threats and attackers, in addition to incremental activities reflected in our operating expenditure step change for cybersecurity.¹³⁴ We are adopting the Australian Signals Directorate's <i>Essential 8</i> recommendations, in addition to elements of the Cybersecurity Framework developed by the US National Institute of Standards and Technology.</p> <p>Refer to our RIN Response – <i>IT Investment Brief - Cyber Security Enhancements</i> for further information.</p> <table> <tr> <td>Forecast capital expenditure \$2.2M (Compliance) \$1.3M (Maintaining Systems)</td><td>Customer benefits Enhanced cybersecurity of JEN's systems and the data stored within them, enabling us to maintain the reliability of our services in a heightened threat environment.</td></tr> </table>	Forecast capital expenditure \$2.2M (Compliance) \$1.3M (Maintaining Systems)	Customer benefits Enhanced cybersecurity of JEN's systems and the data stored within them, enabling us to maintain the reliability of our services in a heightened threat environment.
Forecast capital expenditure \$2.2M (Compliance) \$1.3M (Maintaining Systems)	Customer benefits Enhanced cybersecurity of JEN's systems and the data stored within them, enabling us to maintain the reliability of our services in a heightened threat environment.		

¹³⁰ AEMC, *National Electricity Amendment (Five Minute Settlement) Rule 2017*, 28 November 2017.

¹³¹ AEMC, *Rule determination, national electricity amendment (global settlement and market reconciliation) rule 2018*, 6 December 2018.

¹³² SCS portion; our AML capital expenditure forecast also contains expenditure relating to this project – refer to Attachment 07-09.

¹³³ The AESCSF was established to address increasing cyber security risks faced by the Australian energy sector, and in response to recommendation 2.10 from the Independent Review into the Future Security of the National Electricity Market. Refer to <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Cyber-Security/Framework-resources>

¹³⁴ Refer to Attachment 06-05 for detail about this operating expenditure step change.

Project	Description	
Other compliance projects	<p>Our forecast includes expenditure to make system changes we expect to be necessary in response to NER changes on the wholesale demand response mechanism and requirements associated with the implementation of a Customer Data Right in the energy sector.</p> <p>Refer to our RIN Response – <i>IT Investment Brief - Wholesale Demand Response</i> and <i>IT Investment Brief - Customer Data Right</i> for further information.</p>	
	<table> <tr> <td>Forecast capital expenditure \$1.5M (Compliance)</td><td>Customer benefits Maintain compliance with regulatory obligations.</td></tr> </table>	Forecast capital expenditure \$1.5M (Compliance)
Forecast capital expenditure \$1.5M (Compliance)	Customer benefits Maintain compliance with regulatory obligations.	
Customer Experience	<p>Our People's Panel made clear recommendations in relation to their experience when dealing with JEN, and they identified shortcomings and lagging performance in the customer experience we provide. The Panel's views (outlined in Attachment 02-02) on these shortcomings confirm previous findings of our customer satisfaction research. A number of these issues are attributable to our IT systems, including limitations on how we can interact with customers through digital channels.</p> <p>To address this feedback, we are proposing to invest in IT-enabled customer service improvements which will allow us to increase the personalisation of customers' interactions with us. This includes developing a customer experience hub to improve integration between our existing customer-facing systems and provide customers with a more seamless experience when dealing with us on different matters—improving on our current experience where a customer needs separate accounts to access outage information, consumption data and connection application information. Our improvements will also ensure we have better access to all relevant information across multiple channels when interacting with a customer, improving our ability to provide timely responses to customer queries. Our forecast also includes expenditure for the lifecycle management of existing and enhanced customer systems.</p> <p>We have quantified the benefits to customers of our proposed improvements and our RIN Response – <i>IT Investment Brief - Customer Experience</i> shows that our investments will result in a net benefit to customers.</p>	
	<table> <tr> <td>Forecast capital expenditure \$2.8M (New Capability)</td><td>Customer benefits Improved customer experience, in line with the expectations outlined by our customers</td></tr> </table>	Forecast capital expenditure \$2.8M (New Capability)
Forecast capital expenditure \$2.8M (New Capability)	Customer benefits Improved customer experience, in line with the expectations outlined by our customers	
Future Grid program	<p>Our Future Grid program includes several capital investments which are defined by the Reset RIN as non-network IT. Information about these initiatives is explained in section 6.3.1.2, our RIN Response – <i>IT Investment Brief - Future Grid Program</i> and our Future Grid investment proposal (Attachment 05-04).</p>	
	<table> <tr> <td>Forecast capital expenditure \$15.7M¹³⁵ (New Capability)</td><td>Customer benefits Increased access for DER exports to the grid, increased access to emerging new energy markets, downward pressure on network prices in long-term due to reduced capital expenditure</td></tr> </table>	Forecast capital expenditure \$15.7M ¹³⁵ (New Capability)
Forecast capital expenditure \$15.7M ¹³⁵ (New Capability)	Customer benefits Increased access for DER exports to the grid, increased access to emerging new energy markets, downward pressure on network prices in long-term due to reduced capital expenditure	

¹³⁵ This is the amount of non-network IT capital expenditure under our Future Grid program, refer to Table 6–8 and Table 6–9 for full program amounts across all expenditure categories.

Project	Description	
Asset Management and GIS minor enhancements	<p>Our GIS and associated asset management systems need to provide timely and accurate geographic data about our distribution network so we can undertake construction, maintenance, fault management and outage notification and restoration activities, as well as for external services such as Dial Before You Dig. They are therefore critical to the continued safe and efficient operation of our network and to maintain the provision of services to customers.</p> <p>Our forecast includes non-recurrent expenditure to maintain the functionality of these systems (with these activities having a lifecycle greater than five years), which is necessary to maintain our current levels of service. It also includes expenditure to make several minor enhancements to our asset management and GIS systems, which will improve the quality of information stored in our GIS system (by modifying processes that include manual intervention that result in the potential for error) and by reducing instances of complex customisations (which currently prevent our GIS system from receiving vendor updates). These minor enhancements are expected to enhance the safety of our services (due to improved accuracy of asset location information, including for Dial Before You Dig requests from customers).</p> <p>Refer to our RIN Response – <i>IT Investment Brief - Asset Mgt and GIS</i> for further information.</p>	
	<table> <tr> <td> Forecast capital expenditure \$2.1M (Maintaining Systems) \$2.6M (New Capability) </td><td> Customer benefits Maintain the reliability of our services and enhance the safety of the network. </td></tr> </table>	Forecast capital expenditure \$2.1M (Maintaining Systems) \$2.6M (New Capability)
Forecast capital expenditure \$2.1M (Maintaining Systems) \$2.6M (New Capability)	Customer benefits Maintain the reliability of our services and enhance the safety of the network.	
SCADA OMS-DMS	<p>This small program relates to minor enhancements to our DMS and OMS systems. These will build on foundational elements of these systems we implemented during the current regulatory period by automating some functions that otherwise require manual intervention (reducing risk of operator error and therefore improving network safety).</p> <p>Refer to our RIN Response – <i>IT Investment Brief - Operational Technology Enhancements</i> for further information.</p>	
	<table> <tr> <td> Forecast capital expenditure \$0.1M (Maintaining Systems) \$0.2M (New Capability) </td><td> Customer benefits Improvements to network safety and maintaining levels of reliability. </td></tr> </table>	Forecast capital expenditure \$0.1M (Maintaining Systems) \$0.2M (New Capability)
Forecast capital expenditure \$0.1M (Maintaining Systems) \$0.2M (New Capability)	Customer benefits Improvements to network safety and maintaining levels of reliability.	

7.2.4 References

Supporting documents included as part of our regulatory proposal or response to the Reset RIN for our forecast non-network IT capital expenditure are listed below.

Document title	Location
Attachment 02-02 Community consultation report	Regulatory proposal
Attachment 05-04 Future Grid investment proposal	Regulatory proposal
Technology plan	RIN Response
IT Investment Brief - 5-Minute Settlement	RIN Response
IT Business Case - 5-Minute Settlement	RIN Response
IT Investment Brief - Future Grid Program	RIN Response
IT Investment Brief - SAP Migration	RIN Response
IT Business Case - SAP Migration	RIN Response
IT Investment Brief - Customer Experience	RIN Response

Document title	Location
IT Investment Brief - System Management	RIN Response
IT Investment Brief - Mobility step change	RIN Response
IT Investment Brief - Cyber Security Enhancements	RIN Response
IT Investment Brief - Customer Data Right	RIN Response
IT Investment Brief - Asset Mgt and GIS	RIN Response
IT Investment Brief - Wholesale Demand Response	RIN Response
IT Investment Brief - Operational Technology Step change	RIN Response
IT Investment Brief - DW and BI Step change	RIN Response
IT Investment Brief - Operational Technology Enhancements	RIN Response
IT Long Term Forecasting Guide	RIN Response
JEN SCADA & RTS Asset Class Strategy	RIN Response

7.3 Motor vehicles

Motor vehicles allow personnel and specialised tools and equipment to travel around our distribution area to perform emergency fault response, repair, maintenance, inspection and construction activities. Our fleet assets are therefore critical to enabling us to deliver standard control services to customers and are particularly important in the context of us efficiently maintaining the safety and reliability of our network. Our principles for managing our fleet assets are to ensure that all assets are:

- fit for purpose, facilitating the safe and efficient carrying out of network operations
- procured and managed to achieve the lowest total lifecycle cost of meeting our operational needs.

Current issues with our motor vehicle assets

As with other assets, the condition of motor vehicle assets deteriorates with usage and over time. Degraded asset condition can reduce functionality and performance, increase ongoing operating costs and in some cases create significant safety risks to the personnel operating these vehicles (which can result in a breach of work health and safety obligations). Over the medium term, there is a relationship between the condition of our fleet assets and the level of network services that we can deliver, for example, a higher risk of fleet asset failure could increase the time taken to respond to network faults. As such, and consistent with our customers' expectations that we maintain our current network service levels, our fleet expenditure aims to maintain an efficient level of fleet asset performance (or failure) risk over the medium term, noting that the overall condition of our fleet can fluctuate over the short term due to the range of factors which influence condition and the relatively high frequency (compared to network assets) that fleet items are turned over.

During the first part of the current regulatory period, we replaced fewer vehicles than we initially planned within the passenger, light commercial and heavy commercial categories. This outcome was mainly due to personnel and organisational structure changes, delaying the progression of internal expenditure proposals and approvals, and the prioritisation of the replacement of some elevated work platform (**EWP**) vehicles which exhibited condition and work health and safety issues. As of 2019, this has resulted in some passenger, light commercial and heavy commercial vehicles being in a poorer condition than our target condition rating over the medium to long term. Although we make vehicle replacement decisions upon assessment of each asset's condition, age (and for some vehicle types, distance travelled) can be a reasonable proxy for condition. As of 2019, some of JEN's passenger, light commercial and heavy commercial vehicles are beyond our lifespan expectations and exhibiting condition

degradation beyond the level we target for this asset class over the medium term. Left unaddressed, this elevated degradation has the potential to result in an increase fleet maintenance costs in the near future.

Furthermore, as part of our periodic reviews of operational fleet requirements, in 2019 we made a decision not to replace 18 vehicles (in addition to 10 trailer and plant items) which were due for condition-based replacement, and instead disposed of these at auction. This reduction in the number of vehicles we have available to support network operations therefore requires higher utilisation of remaining fleet assets and increases the risk that the unplanned withdrawal from service of a vehicle (for example, due to mechanical breakdown) would result in not enough vehicles available for use. This therefore reduces our ability to continue to use existing degraded assets significantly beyond their economic lives while still maintaining our network service levels in the future.

Our forecast reflects the expenditure required to replace (or where economic, refurbish) end-of-life vehicles to achieve our target level of risk associated with our fleet assets over the medium term. In line with the issues described above, and as shown in Figure 7–5, we are planning to address this current level of risk by undertaking a higher number of vehicle replacements in the final year of our current regulatory period and the first year of our next regulatory period, removing this backlog of overdue vehicle replacements. After these near-term replacements, our expenditure forecast reduces significantly, and in aggregate, our forecast fleet expenditure for the next regulatory period is approximately 40 per cent lower than our actual and estimated expenditure during the current regulatory period.

Replacement planning

We use a combination of age and distance thresholds to estimate the required replacement timing of each asset within our fleet. These replacement planning thresholds take into account differences in the way each type of vehicle is used and is likely to perform over its life, also compliance with Australian Standards (**AS**) for the rebuild of elevated work platforms and crane equipment after ten years in service.¹³⁶ While noting that vehicles will be subjected to different uses and conditions in other distribution networks, our replacement planning thresholds are broadly consistent with those applied by other distributors, as outlined in Table 7–5.

¹³⁶ Australian Standards AS 1418 (Crane, Hoist and Winches) and AS 2550 (Crane, Hoist and Winches – Safe Use) require EWPs (and any cranes/lifting devices fitted to heavy commercial vehicles) to undergo a major inspection after 10 years of service, involving examination of all critical components. Section 6.4.5 of AS 2550 states that this includes stripping down and removing paint, grease and corrosion from critical components to allow a complete and thorough inspection.

Table 7–5: SG Fleet comparison of vehicle replacement planning thresholds

Company	Passenger vehicles	Light commercial vehicles	Heavy commercial vehicles (including EWP)
Essential Energy	60 months/150,000 km	60 months/150,000 km	10-15 years
Ausgrid	48 months/80,000 km (leased)	84 months/150,000 km (leased)	15 years
Powerlink	4 years	4 or 7 years	8-10 years
Ergon	48 months/100,000 km	150,000 km	10-15 years
Energex	3 or 5 years	5 years	10-15 years
SA Power Networks	60 months/150,000 km	60 months/150,000 km	10 years (EWP) 15 years (crane)
Powercor	60 months/150,000 km	60 months/150,000 km	10-15 years (EWP) 10 years (HCV)
Downer	36 months/90,000 km	36 months/90,000 km	7-10 years
JEN	60 months/150,000 km	60 months/150,000 km	10-15 years (EWP) 10 years (HCV)

Source: SG Fleet

For EWPs, we adopt different replacement policies between different sized vehicles.¹³⁷ Our single-person EWPs are 10.4 tonne gross vehicle mass (**GVM**) trucks fitted with 11 to 13 metre reach elevating platforms. These single-person EWPs are allocated to personnel and designed for on-call emergency response duties around the network, and therefore travel longer distances and accrue more usage hours than other EWPs.¹³⁸ Our policy is to replace single-person EWPs after 10 years in service, after which they must be subject to a full strip-down inspection and rebuild under AS 2550. In contrast, our large EWPs are typically 15 to 22.5 tonne GVM trucks fitted with 13 to 22 metre working height elevating platforms. Although they can be used for fault response, these large EWPs are mainly used for planned construction works. These vehicles reside at our depots and are returned each day. Our policy is to undertake a major inspection and rebuild after ten years in line with AS 2550, and these vehicles are then replaced after a further five years of service.

In practice, a range of factors will determine a specific vehicle's optimal replacement age to minimise total lifecycle cost—such as how a particular vehicle is used, the conditions it is used in, its model and whether it has any mechanical defects. We, therefore, undertake safety and condition inspections at regular intervals and before any replacement decision is made, to determine whether a vehicle is replaced or whether its planned replacement can be efficiently deferred.

Procurement approach

We periodically assess our procurement approach (leasing or outright purchase) for vehicles and our desired vehicle attributes such as drive train type (for example, internal combustion engine or electric) to ensure our fleet assets continue to be fit for purpose and represent the lowest total lifecycle cost. Our most recent analysis demonstrated that outright ownership represents a lower cost to our customers on a lifecycle basis for all vehicle types, noting also that ownership provides more flexibility for us to reduce our fleet size in the future if necessary without incurring lease break costs. We have therefore proposed expenditure to procure vehicles within our forecast capital expenditure for the next regulatory period, and have not proposed any operating expenditure step changes relating to vehicle leases. This is consistent with our procurement approach during the current regulatory period.

¹³⁷ Note that as all JEN's EWPs have a GVM greater than 4.5 tonnes, therefore we have reported all EWPs under the *elevated work platform (HCV)* category in our response to the Reset RIN.

¹³⁸ As a rough guide, every hour of EWP usage equates to approximately 50 kilometres travelled, meaning a typical single-person EWP may have the equivalent of 400,000 to 500,000 kilometres of usage by the time it is replaced at 10 years old.

We have also analysed the total lifecycle costs of electric vehicles relative to the diesel and petrol vehicles we currently have in our fleet. There have been significant advances in small-scale battery storage technology during the current regulatory period, with storage capacity increasing and costs decreasing. We have considered advances in electric vehicle technology to assess whether they now represent a cost-efficient alternative to traditional drivetrains and whether they would meet our operational requirements. This involves assessment of capital-operating expenditure trade-offs, as electric vehicles typically have higher upfront purchase prices (capital expenditure) but lower ongoing running costs (operating expenditure). The unit costs we have used to develop our forecast capital expenditure continue to be based on diesel drivetrains (petrol for passenger vehicles), with these sourced from market providers. We will continue to analyse these trade-offs during the next regulatory period and procure the drivetrain type which meets our operating requirements and represents the least-cost option over the vehicle's total lifecycle, consistent with our fleet management principles.

Our actual and forecast motor vehicle expenditure is shown in Figure 7–5, and our forecast by vehicle type is set out in Table 7–6. Our forecast also contains expenditure on mobile plant items which don't fall into any of the motor vehicle categories as defined in the Reset RIN (mostly trailers)—this expenditure is explained in section 7.5.

Figure 7–5: Motor vehicle expenditure (\$ June 2021, millions)

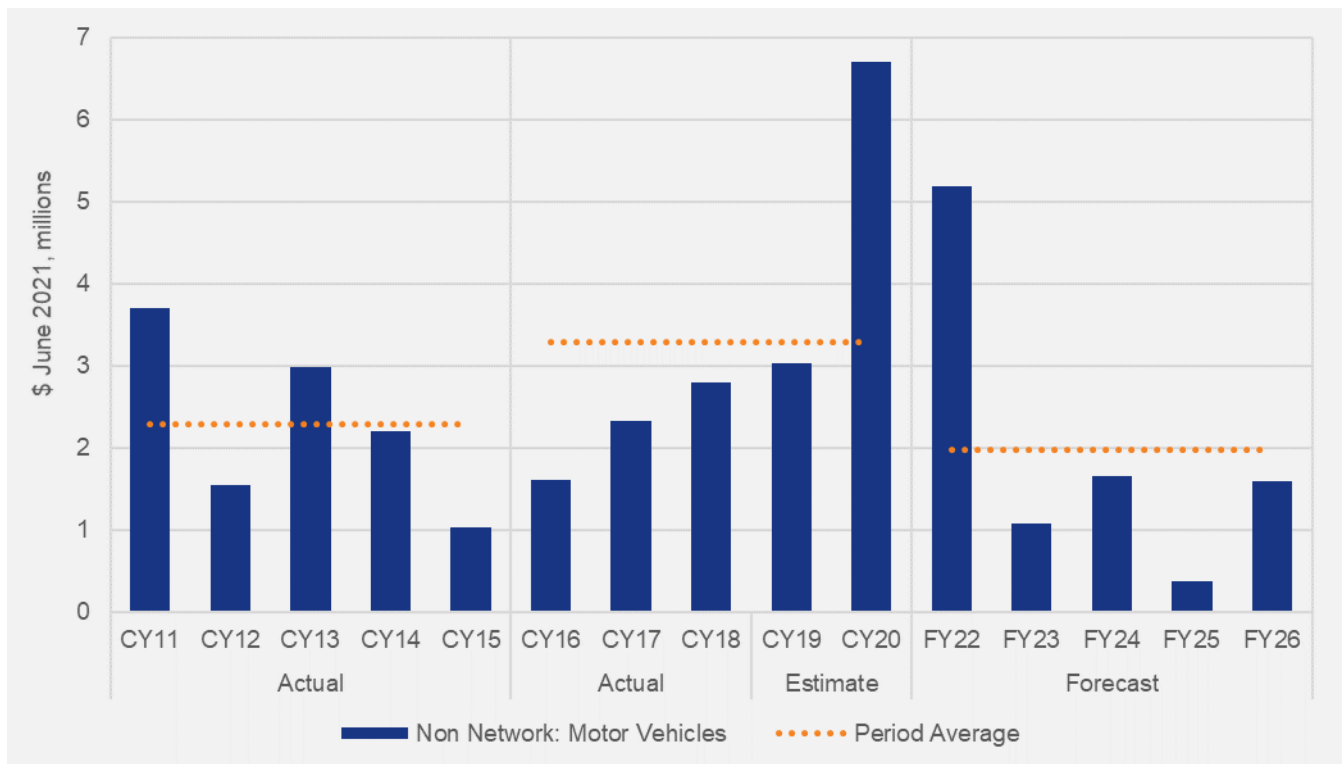


Table 7–6: Forecast motor vehicle expenditure by category (\$ June 2021, millions)

Vehicle category	FY22	FY23	FY24	FY25	FY26	Total
Car	0.5	0.6	0.1	0.1	0.4	1.6
Light commercial vehicle	1.2	0.0	1.1	0.1	0.5	2.9
Elevated work platform (LCV)	0.0	0.0	0.0	0.0	0.0	0.0
Elevated work platform (HCV)	1.6	0.2	0.0	0.0	0.0	1.7
Heavy commercial vehicle	1.9	0.4	0.5	0.2	0.7	3.6
Total motor vehicle expenditure	5.2	1.1	1.7	0.4	1.6	9.9

7.3.1 References

Supporting documents included as part of our regulatory proposal or response to the Reset RIN for our forecast motor vehicle capital expenditure are listed below.

Document title	Location
JEN Fleet Asset Class Strategy	RIN Response

7.4 Buildings and property

Our buildings and property capital expenditure forecast covers expenditure on buildings and fixed furnishings at JEN's depots (which we own) and corporate offices (which we lease, but are responsible for office fit-outs).

During the previous two regulatory periods, our major office leases became due for expiry, and several health and safety issues at our depot sites required addressing. We took this opportunity to undertake a major review of our whole-of-business office and field-based accommodation requirements over the long term. This review resulted in us relocating and consolidating several office sites and constructing two new depots to accommodate field-based employees. Our property capital expenditure during this time was elevated due to the construction of our Tullamarine and Broadmeadows field sites and fit-outs of our two new corporate office sites.

Following this period of heightened property expenditure and relocation to new long-term accommodation, our forecast property capital expenditure for the next regulatory period has reverted to normal levels. During the next regulatory period, we intend to undertake necessary minor refurbishment works at our four existing sites as some components of these fit-outs reach the end of their useful lives, primarily driven by:

- end of life replacement or upgrades to essential services (mechanical, electrical, fire and hydraulics systems) to ensure we continue to maintain compliance with building and safety regulations
- replacement of building security systems (such as access pass scanners) where vendors no longer support them
- maintaining the currency of office accommodation and other facilities to promote a highly productive and engaged workforce, including ensuring that all sites continue to meet health and safety, Disability Discrimination Act and Building Code of Australia requirements
- ad-hoc capital expenditure to address unforeseen damage or failure of building systems, fixtures or fittings.

Our forecast capital expenditure on items such as office furniture and equipment is included under the non-network other category¹³⁹—refer to section 7.5.

¹³⁹ Consistent with the expenditure category definitions contained in the Reset RIN.

Figure 7–6: Non-network buildings and property expenditure (\$ June 2021, millions)

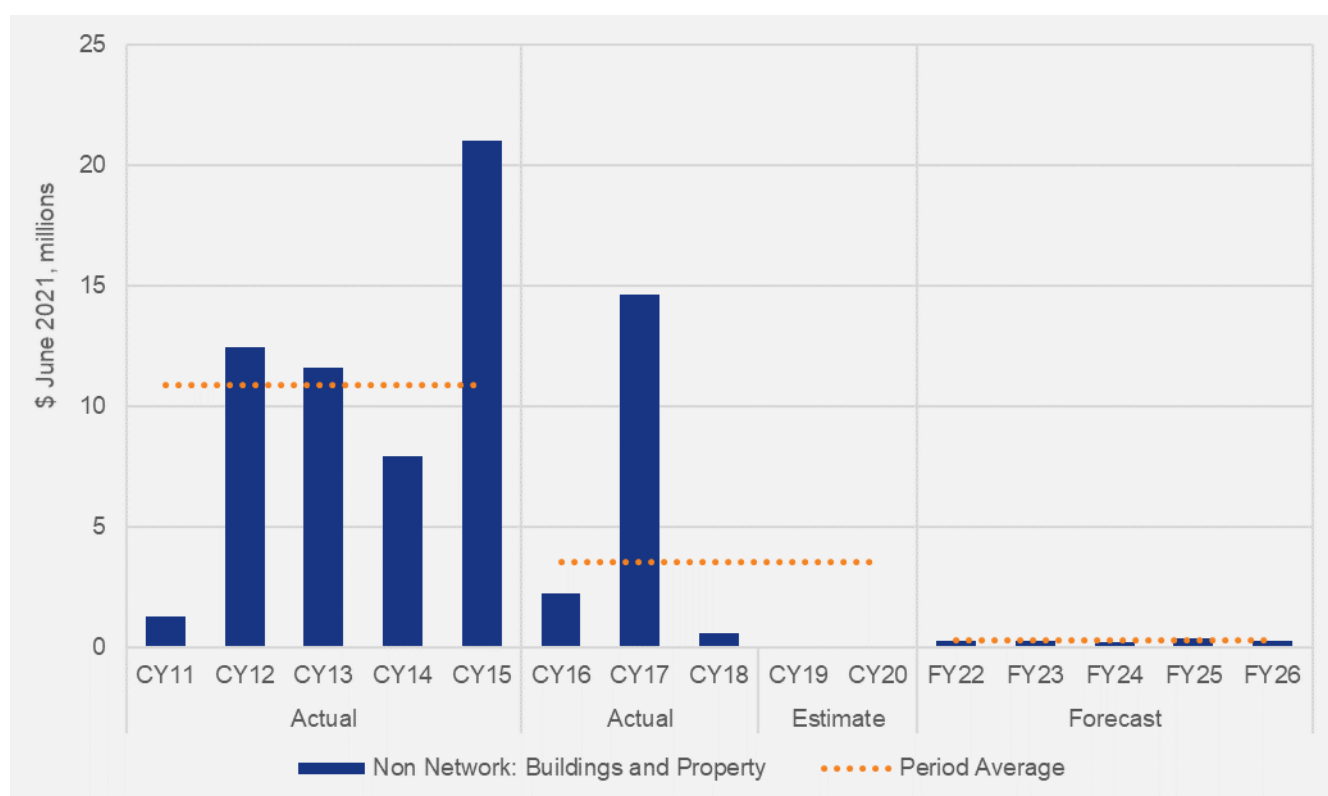


Table 7–7: Forecast non-network buildings and property expenditure (\$ June 2021, millions)

Category	FY22	FY23	FY24	FY25	FY26	Total
Buildings and property	0.2	0.3	0.2	0.4	0.2	1.3

7.4.1 References

Supporting documents included as part of our regulatory proposal or response to the Reset RIN for our forecast buildings and property capital expenditure are listed below.

Document title	Location
JEN Property Asset Class Strategy	RIN Response

7.5 Other

This category covers expenditure on non-network assets other than those which fall into the categories set out above. The non-network other capital expenditure contained in our forecast consists of:

- **Tools and equipment used by personnel working on JEN's network.** This covers the replacement of handheld and other mobile tools and equipment for overhead, underground and zone substation construction, maintenance, inspection and testing. Tools and equipment are replaced periodically to ensure they continue to perform as required. Our approach to replacement is outlined in our Tools and Equipment Asset Class Strategy.
- **Office furniture and equipment.** This includes non-fixed items of office furniture and equipment, such as desks, chairs and kitchen equipment. Our forecast expenditure on office furniture and equipment is closely related to our expenditure on buildings and property minor refurbishments, as set out in section 7.4. During the forecast period, we will undertake minor refurbishment works at our two office sites and depot sites to replace items of equipment which have reached the end of their useful lives. This approach is explained further in our Property Asset Class Strategy.
- **Other plant and equipment which does not fall within a motor vehicle category.** We have some types of mobile plant (such as trailers) which do not fall within a category of motor vehicle as defined by the Reset RIN. The characteristics of these assets and our approach to their lifecycle procurement, maintenance and replacement are consistent with our approach to motor vehicle assets, as set out in section 7.3 and described further in our Fleet Asset Class Strategy. We replace trailers at the end of their useful lives to ensure they remain in a safe and roadworthy condition and can be relied upon to support network operations. In our planning, we adopt a 15-year replacement cycle for trailers. However, each asset is subject to safety and condition inspections and is only replaced when it is unable to meet our requirements. During the current regulatory period, we reduced the size of our plant and equipment fleet, disposing of ten mobile plant items which were due for condition-based replacement.

Figure 7–7: Non-network other expenditure (\$ June 2021, millions)

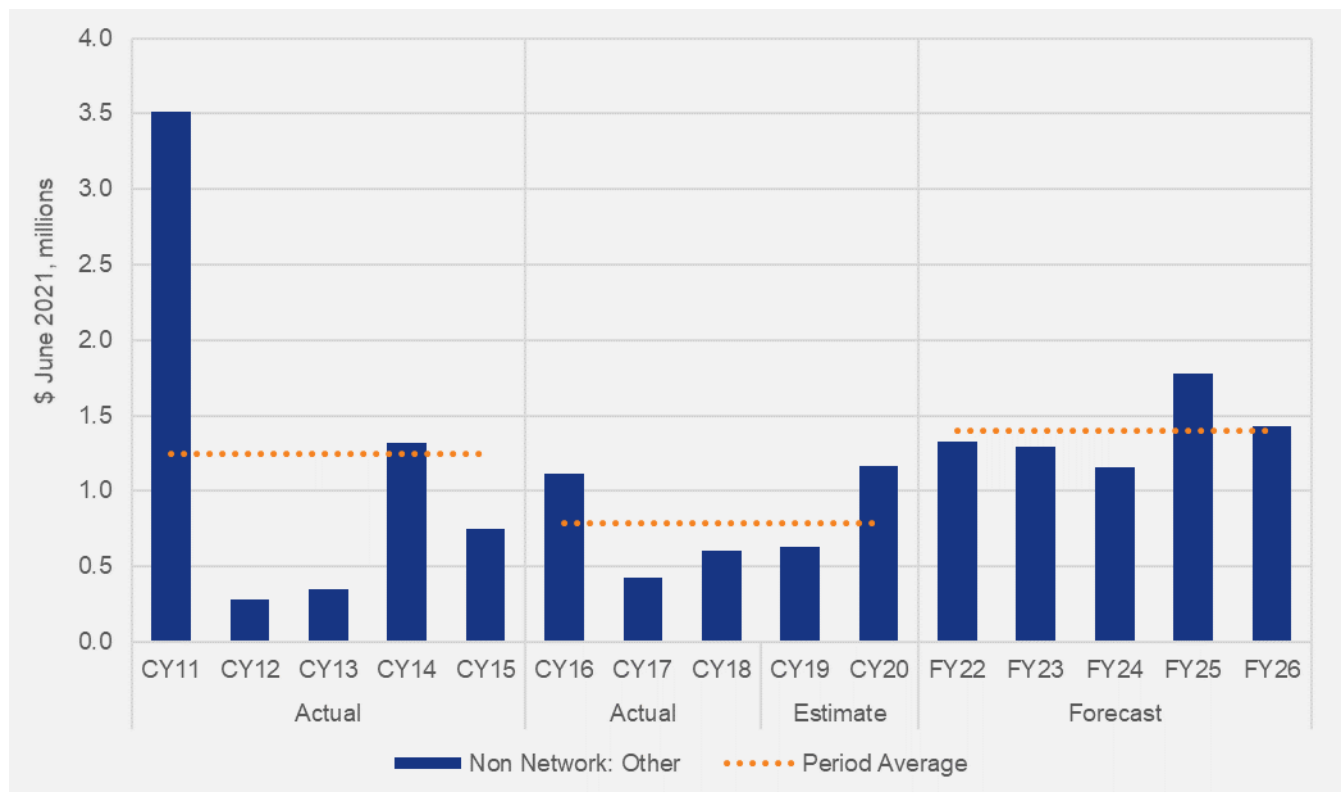


Table 7–8: Forecast non-network other capital expenditure by category (\$ June 2021, millions)

Category	FY22	FY23	FY24	FY25	FY26	Total
Tools and equipment	0.5	0.5	0.5	0.5	0.5	2.4
Office furniture and equipment	0.7	0.8	0.6	1.1	0.7	3.8
Trailers and non-motor vehicle plant ¹⁴⁰	0.1	0.0	0.1	0.2	0.3	0.8
Total non-network other expenditure	1.3	1.3	1.2	1.8	1.4	7.0

7.5.1 References

Supporting documents included as part of our regulatory proposal or response to the Reset RIN for our forecast other non-network capital expenditure are listed below.

Document title	Location
JEN General Tools & Equipment Asset Class Strategy	RIN Response
JEN Property Asset Class Strategy	RIN Response
JEN Fleet Asset Class Strategy	RIN Response

¹⁴⁰ Plant which is covered by the Reset RIN's motor vehicle category definitions is discussed in section 7.3.

Appendix A

Feedback on our draft plan

A1. Feedback on our draft plan

The table below sets out the specific feedback we received on our draft plan¹⁴¹ (and from whom) in relation to our capital expenditure, as well as our responses to this feedback.

Who	Topic	Feedback	Our response
Energy Consumers Australia (ECA)	Trust and transparency	The ECA was positive in its review of our approach to engagement but expressed some scepticism as to whether it would lead to changes to the Draft Proposal as input to the regulatory proposal.	<p>We built our plans based on the views of our customers, including the recommendations of our People's Panel. As a result of the responses from our stakeholders to our Draft Proposal, we have amended our plans:</p> <ul style="list-style-type: none"> • Spencer & Co on behalf of ECA suggested a panel of customers and experts could be involved in future decision making with respect to the Future Grid. We have therefore asked our People's Panel if we can continue to engage them. • Spencer & Co also suggested we give some thought to ensuring customers did not pay twice if the customer experience program also led to an incentive payment under the Small Scale Incentive Scheme. We have chosen not to propose such a scheme on this advice.
JEN's Customer Council & People's Panel	Capital expenditure overall	Both the Customer Council and People's Panel felt that more time was needed to absorb concepts in order to make more informed decisions during engagement sessions.	We held additional People's Panel forums to cover more topics and allow more time to process and discuss certain topics.

¹⁴¹ Available at <https://yourgrid.jemena.com.au/draft-plan>

Who	Topic	Feedback	Our response
All groups	Future planning and processes	While the People's Panel felt the Draft Proposal was successful in terms of addressing sustainability, overall, our customers and stakeholders felt the 5 years of the next regulatory period was too constraining in terms of JEN's ability to plan for a flexible future. Our customers were also concerned with how the costs associated with our Future Grid program would be attributed to them.	<p>We have examined the challenges posed by the rapid development of new energy technologies and considered how our customers will use the network differently in the future. We will seek to enable customers to connect renewable energy generation, storage and other distributed energy resources to the network at an increasing rate despite growing technical challenges. We plan to address these challenges through our Future Grid program, mainly through optimised investments in new technologies to make the grid smarter.</p> <p>With respect to costs, our Future Grid program will allow us to defer network investment, and help enable downward pressure on wholesale electricity prices over time (by enabling more energy from solar PV to be exported to the grid), meaning there should be an overall reduction in energy costs for all customers in the long term.</p>
People's Panel	Capital expenditure overall	The People's Panel acknowledged that we had listened to their recommendation that strategic maintenance only be carried out to preserve current levels of reliability.	Of the thirteen key recommendations made by the People's Panel, two related to reliability in that JEN was asked to maintain the number and duration of outages – and not incur additional expenditure to reduce the number or duration of outages. Our capital expenditure and operating expenditure forecasts reflect the level of expenditure required to maintain our current levels of network reliability.

Who	Topic	Feedback	Our response
ECA	Capital expenditure overall	Our reduction in proposed capital expenditure, relative to that projected in the current regulatory period, was seen as a positive step by the ECA in that it would contribute to downward pressure on our Regulated Asset Base and in turn, customer's bills. We were asked however why we had underspent in the early years of the current regulatory period and whether we anticipated the same issue for the next regulatory period.	JEN's replacement capital expenditure forecasting methodology for the current regulatory period over-estimated the routine asset replacement activities required. Upon inspection of these assets, we found the condition of the assets such that they did not warrant replacing. Also, there was a slower load growth in the north of JEN's network leading to less augmentation expenditure being required. Further explanation of our current regulatory period's capital expenditure is provided as Attachment 05-02. Our forecast replacement capital expenditure for the next regulatory period is more closely aligned with our actual volume of replacements in the current regulatory period; therefore we don't expect a similar underspend in the future.
Business customers (through Customer Council)	Capital expenditure overall	Business customers voiced their concern about grid connection processes across distribution businesses in that some requests for connection of new solar PV have been refused. The reasons provided by DNSPs include that there is already too much solar on their network or they have no need for excess generation.	Our Future Grid proposal directly addresses situations where customers may be prevented from connecting solar PV systems to the distribution network, with investments in these activities included in our regulatory proposal.
All groups	Capital expenditure overall	A desire was expressed for more detail on our proposed expenditure than was available in our Draft Proposal to form better opinions. It was however acknowledged that we provided detail in our deep dive session following the Draft Proposal's release.	We intended to provide the additional detail in our Regulatory Proposal as well as the deep dives. After submission of the regulatory proposal, there is also an opportunity for our stakeholders to provide feedback through the AER's price reset process.

Who	Topic	Feedback	Our response
All groups	Replacement capital expenditure	Questions were raised during our deep dive session regarding reliability targets, what information we receive from our network on performance, and whether our replacement expenditure was modelled using the AER's Repex model.	We developed our replacement expenditure forecast in our Draft Proposal to aligned with our People's Panel recommendation that we maintain, not improve, our network reliability, while also being mindful of the reliability incentives available through the STPIS. Our forecast method for replacement capital expenditure is primarily based on our Condition Based Risk Management approach, which we then compare on a top-down basis with the forecast from the AER's Repex model. We are however proposing new network monitoring technology to enable more automated network performance capability within our Future Grid program, which we expect to put downward pressure on replacement capital expenditure over the long term.
All groups	Connections capital expenditure	We were also asked whether the increasing proportion of underground assets were increasing our costs and this contributing to increased customer charges.	The vast majority of the increase in underground assets relates to the connection of new customers in greenfield areas, such as residential estate developments. The developers of those areas incur the incremental capital costs of underground networks (compared to overhead networks) in these areas, not our existing customer base.
All groups	Connections capital expenditure	We were asked to provide the breakdown between routine and non-routine connections and the net capital expenditure (after capital contributions are taken into account). We were also asked to present the forecast growth in customer connections in the context of historic growth to show alignment with recent trends.	Our regulatory proposal provides a breakdown between routine and non-routine connections, as well as showing net capital expenditure. Our proposal also sets out the basis of our forecast growth in support of the reasonableness of this forecast.
All groups	Non-network capital expenditure	The Consumer Challenge Panel (CCP17) has voiced general concern in relation to growing IT investment across the National Energy Market, especially without transparency of how the money is being spent and what the benefits customers can derive from it are. We were asked to provide details on both capital and operating IT expenditure to provide greater visibility.	Our regulatory proposal demonstrates that our forecast IT capital expenditure is materially below that of our current regulatory period, and counter to the trends exhibited in the NEM. ¹⁴² We have developed our forecast IT capital expenditure in line with the AER's <i>Non-network ICT capex assessment approach</i> guidance note, which requires network business to demonstrate efficient expenditure. Finally, we take a top-down approach to determining operating expenditure—which includes IT operating expenditure—and we apply a productivity adjustment of 0.5% to ensure cost-efficiency.

¹⁴² AER, *Consultation paper, ICT Expenditure Assessment*, May 2019, Figure 1.

Who	Topic	Feedback	Our response
Customer Council	Distributed Energy Resources	We were asked to provide additional information regarding plans to connect more solar to the grid while maintaining safety and reliability. The potential for inverters frequently 'tripping' due to high voltage levels on the network was of concern and a suggestion of setting higher inverter standards and fixing substation transformer issues was made.	<p>Our Regulatory Proposal details our plans for modifying the grid and our systems to enable customers to connect more DER, such as rooftop solar systems.</p> <p>Our proposed Future Grid program details these plans for improving our connection processes, working with customers and installers to standardise solar inverter settings, upgrading low-voltage assets to increase the amount of power the grid can receive from customers (commonly referred to as 'hosting capacity') and providing commercial and residential DER customers with an option of having dynamic export limits.</p>
People's Panel	Distributed Energy Resources	Our People's Panel suggested provision of additional information to customers on connection of solar to the grid and smart capabilities would strengthen our plan to provide incentives for households to invest in renewable energy.	We actively share the recommendations and views expressed by the People's Panel with regulators, rule makers and the wider industry to highlight the changing and growing desire of the community to have an energy system that supports an increasingly renewable future. Additionally, our Future Grid proposal will help ensure that more solar PV exports can be accommodated by the grid, ensuring that a greater number of customers have access to feed-in tariffs (thus providing an incentive for customers to invest in renewable generation).
Customer Council	Customer experience	Our Customer Council also asked how our plans to enhance customer experience, provide energy data and enhance security would be implemented, monitored and shared with customers.	We are keen to maintain contact with our customers through the People's Panel and have sought permission to continue to work with them to facilitate continuous input and feedback to our customer experience improvements, with our capital expenditure forecast reflecting the expenditure necessary to implement these improvements. We have also tried to learn from other organisations with excellent reputations for customer service and customer experience.

Appendix B

Compliance with National Electricity Rules

We have considered whether our planning and forecasting processes, and our resultant capital expenditure forecast, are consistent with the capital expenditure objectives¹⁴³ and capital expenditure criteria,¹⁴⁴ as well as considering the capital expenditure factors¹⁴⁵ set out in the NER.

Our forecasting processes explicitly considers the drivers of capital expenditure set out in the capital expenditure objectives, and through our international best practice governance framework we have addressed the matters raised in the criteria. In relation to the resultant capital expenditure forecasts, our forecast capital expenditure is consistent with the requirements of the NER in that it reflects expenditure which is both prudent and efficient.

B1. Why our capital expenditure forecast is required to achieve the objectives in clause 6.5.7(a) of the NER

We have developed our capital expenditure forecast to achieve four key objectives set out in section 1.4. These objectives also reflect and are consistent with the capital expenditure objectives set out in the NER. We have primarily achieved this by (among other things):

- Conducting detailed analysis of the actual condition and age of our assets
- Assessing the sufficiency of our current compliance with regulatory obligations to identify required investments for corrective actions
- Assessing foreseeable changes in the external environment that will impact the level of risk associated with the provision of services to customers, and therefore the capital expenditure required to address these risks
- Quantifying customer-initiated requests to connect to our network as informed by various expert demand reports
- Incorporating real cost escalators to our input costs prepared by independent experts.

The table below summarises how we have complied with each of the capital expenditure objectives.

Capital expenditure objective	NER reference	Actions to ensure compliance
Meet or manage the expected demand for standard control services over that period	6.5.7(a)(1)	We have forecast our relevant capital expenditure categories to take into account the maximum demand, consumption, customer number and construction activity forecasts prepared by ACIL Allen Consulting and the Australian Construction Industry Forum.
Comply with all applicable regulatory obligations or requirements associated with the provision of standard control services	6.5.7(a)(2)	We have assessed our current compliance processes against our obligations as well as assessing any necessary corrective actions and additional new obligations. Our existing systems and processes—including our governance framework and ISO 55001-certified Asset Management System—ensure that our compliance with all applicable regulatory obligations is planned and maintained.

¹⁴³ NER cl 6.5.7(a).

¹⁴⁴ NER cl 6.5.7(c)(1).

¹⁴⁵ NER cl 6.5.7(e).

Capital expenditure objective	NER reference	Actions to ensure compliance
<p>To the extent there is no applicable regulatory obligation or requirement in relation to:</p> <ul style="list-style-type: none"> (i) the quality, reliability or security of supply of standard control services; or (ii) the reliability or security of the distribution system through the supply of standard control services, <p>to the relevant extent:</p> <ul style="list-style-type: none"> (iii) maintain the quality, reliability and security of supply of standard control services; and (iv) maintain the reliability and security of the distribution system through the supply of standard control services 	6.5.7(a)(3)	<p>Our capital expenditure forecast has been developed with consideration of the impact of our changing external environment, compliance obligations, the actual condition of our assets and their age, the current and forecast utilisation of our assets and the effect these influences have on the quality, reliability and security of supply of standard control services. Where no applicable regulatory obligation exists, our expenditure forecasts are targeted at maintaining the current quality, reliability or security of supply, and maintaining the reliability and security of the distribution system. This is also consistent with the views our customers have expressed through our engagement program in relation to their preferences around service levels.</p>
Maintain the safety of the distribution system through the supply of standard control services	6.5.7(a)(4)	<p>Our capital expenditure forecast has been developed with consideration of the impact of our changing external environment, compliance obligations, the actual condition of our assets and their age, the current and forecast utilisation of our assets and the effect these influences have on the quality, reliability and security of supply of standard control services. We have also considered trends in asset failures and customer reports of safety issues as these may be indicative of potential safety issues in the future. Our forecast capital expenditure will allow us to comply with our Electricity Safety Management Scheme (ESMS). Our ESMS, which is overseen by Energy Safe Victoria, is a key control in ensuring the safety of the distribution system is maintained. Safety is JEN's number one priority.</p>

B2. How our capital expenditure forecast reflects the criteria in clause 6.5.7(c) of the NER

We have developed our capital expenditure forecast to comply with the capital expenditure criteria specified in the NER. We have primarily achieved this by:

- employing our best-practice expenditure planning and governance processes, including our ISO 55001-accredited Asset Management System, to ensure that optimal planning and investment decisions are made which minimise the total lifecycle cost of achieving our expenditure objectives and providing services to customers
- engaging an external expert to develop maximum demand and customer number forecasts, and continuing to use a risk-based, probabilistic planning approach to our augmentation and replacement expenditure

- applying Condition Based Risk Management modelling to ensure our replacement activity volumes are based on the best available information about the actual condition and health of our assets, allowing us to only replace (or remediate) assets when necessary in order to maintain service levels, avoiding unnecessary early replacements
- using efficient unit rates—which have been influenced by the strong incentives of the Capital Expenditure Sharing Scheme during the current regulatory period—to develop key parts of our capital expenditure forecast, in addition to obtaining independent bottom-up cost verifications of several major non-routine projects we propose to undertake
- fully exploring the potential for capital-operating expenditure trade-offs and non-network alternatives in our augmentation, replacement and non-network expenditure forecasting, with our proposal allowing us flexibility to undertake demand management (operating expenditure) where economic to reduce load at risk due to growing demand
- employing combinations of bottom-up and top-down forecasting methodologies when developing our proposal, including using top-down methods to challenge bottom-up forecasts, and ensuring delivery and scope efficiencies are reflected in our total forecast expenditure
- considering future levels of customer demand and opportunities to de-rate assets in our replacement planning, resulting in us reducing our replacement expenditure forecast compared to undertaking like-for-like replacements
- employing our robust cost estimation methodology and procurement processes to ensure all input costs to our capital expenditure forecast are efficient
- considering interdependencies with other areas of our regulatory proposal, particularly our operating expenditure forecast (which reflects the expenditure required to support ongoing asset maintenance and inspection activities which are necessary in the context of our efficient condition-based asset replacement and augmentation programs)
- not including any *expenditure for a restricted asset*¹⁴⁶ in our forecast.

B3. How our capital expenditure forecast accounts for the factors in clause 6.5.7(e) of the NER

The NER sets out the capital expenditure factors the AER must have regard to when deciding whether or not it is satisfied that our capital expenditure forecast reasonably reflects the capital expenditure criteria. The table below sets out points we consider relevant to each of the capital expenditure factors.

Capital expenditure factor	NER reference	JEN comments
The most recent annual benchmarking report that has been published under rule 6.27 and the benchmark capital expenditure that would be incurred by an efficient Distribution Network Service Provider over the relevant regulatory control period	6.5.7(e)(4)	As a high-level assessment of relative capital efficiency, JEN ranks a clear fourth on capital multilateral partial factor productivity as set out in the AER's Annual Benchmarking Report (November 2019). This benchmark performance suggests that despite JEN's scale disadvantage, we are managing to produce more with less, relative to our peers.

¹⁴⁶ As set out in the NER, *expenditure for a restricted asset* means capital expenditure for a *restricted asset*, excluding capital expenditure for the refurbishment of that asset.

Capital expenditure factor	NER reference	JEN comments
The actual and expected capital expenditure of the Distribution Network Service Provider during any preceding regulatory control periods	6.5.7(e)(5)	JEN has a proven record in responding efficiently to expenditure (and related service performance) incentives while still safely and reliably delivering services to customers. We have illustrated trends in our capital expenditure over preceding regulatory control periods throughout this document. Attachment 05-02 also discusses our current period's capital expenditure in further detail.
The extent to which the capital expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the Distribution Network Service Provider in the course of its engagement with electricity consumers	6.5.7(e)(5A)	We have engaged extensively with our customers in developing our regulatory proposal, including our capital expenditure forecast. Attachment 02-01 details our engagement program, and the section titled ' <i>How have we responded to customer feedback in our forecast?</i> ' in the overview of this document details specific parts of our capital expenditure forecast which reflect the views of our customers.
The relative prices of operating and capital inputs	6.5.7(e)(6)	As outlined in our Asset Class Strategies, we employ whole-of-lifecycle management planning for our assets, which considers strategies and options over the entire life of an asset (from planning to disposal) to deliver the lowest long-term sustainable costs required to achieve our objectives. Lifecycle management focusses on ensuring an effective and efficient balance between maintenance (operating expenditure) and replacement (capital expenditure) of assets, based on analysis of asset safety, cost, risk and reliability. Additionally, we have utilised consistent input cost escalators for our capital and operating expenditure forecasts.
The substitution possibilities between operating and capital expenditure	6.5.7(e)(7)	We routinely analyse ways to optimise the economic life of our assets, with various examples of this analysis are included throughout our regulatory proposal and supporting materials. We continuously seek to optimise our expenditure decisions. During a regulatory period, this may result in us increasing operating expenditure in place of planned capital expenditure—or vice-versa—where efficient. For example, we assess whether asset replacement can be deferred by substituting capital expenditure with further maintenance—where it leads to lower long term average costs to our customers—having regard to the safety and reliability risks associated with these decisions. We also assess whether network augmentation and replacement projects can be deferred by utilising non-network alternatives, such as demand management as explained in sections 4 and 6.
Whether the capital expenditure forecast is consistent with any incentive scheme or schemes that apply to the Distribution Network Service Provider under clauses 6.5.8A or 6.6.2 to 6.6.4	6.5.7(e)(8)	Our capital expenditure forecast reflects the prudent and efficient expenditure required for us to maintain our current levels of network reliability, consistent with the incentives provided by the Capital Efficiency Sharing Scheme, Service Target Performance Incentive Scheme, Demand Management Incentive Scheme and the Demand Management Innovation Allowance Mechanism.

Capital expenditure factor	NER reference	JEN comments
The extent the capital expenditure forecast is referable to arrangements with a person other than the Distribution Network Service Provider that, in the opinion of the AER, do not reflect arm's length terms	6.5.7(e)(9)	Our forecast capital expenditure has been developed through our capital forecasting and governance process outlined in this document and our Procurement Policy, which ensures prudent and efficient procurement outcomes. Refer also to JEN's response to section 28 of Schedule 1 of the Reset RIN for a description of JEN's related party arrangements.
Whether the capital expenditure forecast includes an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b)	6.5.7(e)(9A)	Our proposed forecast capital expenditure does not include an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b).
The extent the Distribution Network Service Provider has considered, and made provision for, efficient and prudent non-network options	6.5.7(e)(10)	<p>We have considered at length the potential for efficient and prudent non-network options when developing our capital expenditure forecast. Through this process, we did not identify any situations where a non-network solution represented the most prudent and efficient option to address an identified need. This document summarises our assessment of non-network options, and our RIN Response – <i>Demand Management Options Analysis report</i> describes this in further detail in relation to specific augmentation projects.</p> <p>As outlined above, we will continue to assess opportunities to employ non-network options during the next regulatory period, and as a result may substitute operating expenditure for capital expenditure where prudent and efficient to do so.</p>
Any relevant final project assessment report (as defined in clause 5.10.2) published under clause 5.17.4(o), (p) or (s)	6.5.7(e)(11)	Our capital expenditure forecast includes a number of projects that are subject to the Regulatory Investment Test for Distribution, as described in section B5.
Any other factor the AER considers relevant and which the AER has notified the Distribution Network Service Provider in writing, prior to the submission of its revised regulatory proposal under clause 6.10.3, is a capital expenditure factor	6.5.7(e)(12)	The AER has not notified JEN of any other factors it considers relevant.

B4. Allocation of expenditure to standard control services

Consistent with the requirement of NER clause 6.5.7(b)(2), JEN's forecast capital expenditure reflects expenditure which has been properly allocated to standard control services in accordance with the principles and policies set out in the JEN CAM.¹⁴⁷

¹⁴⁷ The JEN CAM that has been approved by the AER and is to apply during the next regulatory period is available at <https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/cost-allocation-method/jemena-cost-allocation-method-2019>

B5. Capital expenditure for options which have satisfied the RIT-D

Consistent with the requirement of NER clause 6.5.7(b)(4), JEN's forecast capital expenditure for the next regulatory period includes capital expenditure that is for an option that has satisfied the regulatory investment test for distribution in relation to following projects identified in Table B5–1.

Table B5–1: Capital expenditure for options which have satisfied the RIT-D

Project	Section reference in this document	Proposed capital expenditure (FY22-26)
Replacement of transformers at Heidelberg zone substation	4.8.1	\$2.6M
Replacement of switchgear at Footscray East zone substation	4.9.1	\$0.6M

Additionally, as at 31 January 2020, we are still in the process of undertaking a RIT-D for the replacement of switchgear and relays at Footscray West zone substation, with consultation on our draft project assessment report open until 14 February 2020.

B6. Key assumptions underlying our capital expenditure forecast

Consistent with the requirements of NER clause S6.1.1(4) and (5), the key assumptions underlying our capital expenditure forecast are listed in our response to paragraph 1.8 of Schedule 1 to the Reset RIN and a certification of the reasonableness of these key assumptions by the directors of JEN is provided as Attachment 05-08.

B7. Explanation of significant variations between forecast and historical capital expenditure

Consistent with the requirement NER clause S6.1.1(7), an explanation of any significant variations in the forecast capital expenditure from historical capital expenditure is provided below.

Table B7–1: Comparison between forecast and historical capital expenditure (Real June 2021, \$M)

Capital expenditure category	Current regulatory period	Next regulatory period
Replacement	191.0	210.9
Connections	193.2	218.0
Augmentation	92.8	146.5
Non-network	154.7	113.9
Capitalised overheads	146.6	91.2
Total	778.2	780.5

(1) Gross capital expenditure.

Key drivers of the differences between our current period's and forecast capital expenditure include:

- the installation of REFCLs at Coolaroo zone substation and associated works necessitated by the installation of REFCLs at Kalkallo zone substation

- strong demand from commercial and industrial customers for connections and from third parties for asset relocation activities
- new initiatives to be undertaken as part of our Future Grid program in response to growing DER penetration
- condition- and risk-based replacement of a number of types of existing assets (including pole top structures and overhead services), and major station rebuild projects for Coburg North and Coburg South zone substations
- IT system changes required to comply with the introduction of five-minute settlement
- a change in our treatment of corporate overheads, with these being expensed from 1 January 2021 consistent with our approved CAM.

This document provides further detail on our forecast capital expenditure for the next regulatory period, while Attachment 05-02 provides further detail about our capital expenditure for the current regulatory period.

Appendix C

Capital contributions

C1. Capital contributions

We connect new customers to our shared electricity network and the connection requirements vary significantly—ranging from a residential customer right through to large business users and generation. A step in the process involves us providing connection offers¹⁴⁸ to potential customers.

As a general principle, connecting customers can take a large amount of planning, effort and cost, depending on the type and size of the connection and whether there is capacity in the network. We need to assess these issues for every connection we make, however, for the vast majority of smaller connections—such as households and small businesses in establishing areas requiring less than 100 Amps¹⁴⁹—we can make a relatively quick assessment, and can charge a set fee for this connection service. This is a fee-based Alternative Control Service.

Connecting embedded generation—particularly rooftop PV generation—is becoming more prevalent, and this presents different challenges, as discussed in section 6.3.1.1.

For our more significant connections—greater than 100 Amps and usually where the augmentation of our network is required—the activities and costs are more complex, so we approach the method for charging quite differently. Essentially, we undertake a cost assessment of the connection, deduct the calculated future network revenues we may potentially earn from the connection (Incremental Revenue, **IR**) and then, if there is a residual amount leftover, we charge this shortfall as a part of our connection offer. This charge is called a capital contribution and the connection service is classified as a SCS. We undertake this process in accordance with regulatory requirements, including the AER's connection charges guideline¹⁵⁰ and the ESC's Guideline 14,¹⁵¹ as well as in accordance with our connection policy¹⁵² (**connection policy**).

Because of the shared nature of the distribution network and the large amounts of augmentation works we must undertake from time to time to connect a customer, the connection activities may involve us building additional capacity in the network than is required by the connecting customer. It is unfair that the connecting customer should be paying for extra capacity (Incremental Cost Shared Network, **ICSN**) that others will use in the future, so we address this in our connection offer process by using standard augmentation rates (\$/kVA) derived from the marginal cost of reinforcement (**MCR**).¹⁵³ We apply the augmentation rates based on the size of the connection to determine the capital contribution rather than the augmentation investment that we must make. Connection costs—that is those costs only used by the connecting customer (Incremental Cost Customer Specific, **ICCS**)—are wholly paid by that connecting customer.

Using these principles, which are set out in regulatory guidelines and our connection policy, we determine the capital contribution amount and include it in the connection offers to potentially connecting customers using the formula:

$$\text{Capital contribution} = IR - ICCS - ICSN$$

To ensure we only recover our efficient cost, we must forecast the amount of capital contribution for connection services as a part of our SCS building block model. Accounting for these revenues this way has tax consequences, and we must also account for these.

To forecast the customer contributions revenue for our building block model in this proposal, we have looked back through our historical capital contributions and considered our connection policy to determine the best way to forecast. We identified that grouping our connections into four distinct categories, and forecasting methodology for each category helped to develop the most reliable forecast. The categories, our forecasting methodology and the reason for that methodology are outlined in Table C1–1.

¹⁴⁸ JEN, *Electricity distribution licence*, 24 September 2008, section 6.

¹⁴⁹ In essence, connections where augmentation is not required.

¹⁵⁰ AER, *Connection charge guidelines for electricity retail customers under chapter 5A of the National Electricity Rules Version 1.0*, June 2012.

¹⁵¹ ESC, *Electricity Industry Guideline No. 14: Provision of services by electricity distributors, Issue 1*, April 2004.

¹⁵² Attachment 05-09.

¹⁵³ Our approach to developing these MCR rates is described in Attachment 05-10.

Table C1–1: Our approach to forecasting capital contributions

Category	Forecasting methodology	Reason for the methodology
Residential brownfield real estate development	<p>We determine the ratio of capital contribution to the actual costs:</p> <ol style="list-style-type: none"> 1. based on the actual costs for connections made in 2018 2. adjusting this ratio for updates in the MCR. <p>We then apply this ratio to our forecast capital expenditure at the <i>residential connection</i> level to determine the amount of capital contributions over the next regulatory period.</p>	<p>We have chosen 2018 historical data as the basis for forecasting capital contributions because it is the most relevant period that reflects the methodology for calculating the capital contributions under the connection policy that we will apply in the next regulatory period.</p> <p>We make adjustments for changes in the MCR as this is the most recent rate, and is the rate we will apply in the next regulatory period.</p>
Residential and business greenfield real estate sub-division development	<p>We determine the ratio of capital contribution to the actual costs:</p> <ol style="list-style-type: none"> 1. based on the average annual actual costs for connections made between 2016 and 2018 2. adjusting this ratio for updates in the MCR. <p>We then apply this ratio to our forecast capital expenditure at the <i>sub-division connection</i> level to determine the amount of capital contributions over the next regulatory period.</p>	<p>We have chosen 2016 to 2018 historical data as the basis for forecasting capital contributions because it is the most relevant period that reflects the methodology for calculating the capital contributions under our connection policy that we will apply in the next regulatory period.</p> <p>We make adjustments for changes in the MCR as this is the most recent rate, and is the rate we will apply in the next regulatory period.</p>
Business – Low voltage and distribution sub-stations	<p>We determine the ratio of capital contribution to the actual costs:</p> <ol style="list-style-type: none"> 1. based on the average annual actual costs for connections made between 2016 and 2018 2. adjusting this ratio for updates in the MCR. <p>We then apply this ratio to our forecast capital expenditure at the <i>Business – Low voltage and distribution sub-stations connection</i> level to determine the amount of capital contributions over the next regulatory period.</p>	<p>We have chosen 2016 to 2018 historical data as the basis for forecasting capital contributions because it is the most relevant period that reflects the methodology for calculating the capital contributions under the connection policy that we will apply in the next regulatory period.</p> <p>We make adjustments for changes in the MCR as this is the most recent rate, and is the rate we will apply in the next regulatory period.</p>
Large, individual customers	<p>We forecast these connection costs individually.</p>	<p>These types of connections are large, unique and very complex and therefore require individual attention. Applying the MCR rate, which represents the average cost of augmentation across the network, may not yield the best estimation of the incremental cost of the shared network. Moreover, they are also relatively infrequent, which means there is no stable historical data on which to base a forward-looking projection.</p>

Once we determine the capital contributions at a category level, we include the revenues in our building block model and then assess the tax allowance requirements.

Appendix D

Asset management system governance

D1. Jemena's asset management system

D1.1 Asset Business Strategy

The purposes of our Asset Business Strategy are to:

- provide a comprehensive analysis of potential future trends over the long-term (i.e. 20 years)
- identify our customers' long-term preferences and ensure that they shape our long-term planning
- identify innovations and changes in technology, policy, and regulation, and their likely influences on how we provide services
- ensure network safety and service quality over the long-term
- assess expenditure scenarios on our overall network performance
- provide a high-level forecast of service costs over the next 20 years, cognisant of the changes in the operating environment which are likely to occur over this time.

D1.2 Asset Class Strategies

Our Asset Class Strategy documents describe the performance and risks of each class of asset that we use to enable the provision of services to customers. We divide our network assets into eight asset classes. Asset Class Strategies are designed to enable the optimum development of asset strategies and plans, and provide information about:

- asset class profiles, including the type, specifications, life expectancy and age profile of the asset class in service across our network
- asset strategies, including key strategies and plans that support Jemena's Business Plan, Asset Management Policy, strategies and objectives, and inform the development of expenditure plans and programs of work
- asset risks, issues and criticality
- asset performance, including information about performance objectives, measures and analysis
- asset expenditure assessments, including expenditure decision-making processes (and how expenditure options are analysed)
- historical and forecast expenditures
- whether to renew or dispose of assets that have reached the end of their economic life based on their performance, risks and/or supply security or service level requirements.

JEN aims to ensure that we optimally manage our assets in our customers' long-term interests. Our Asset Class Strategies use leading asset management techniques to ensure we strike an efficient balance between capital and operational expenditure through the consideration of total lifecycle management costs. However, different asset classes will have different lifecycle management strategies; therefore, we examine these options and trade-offs for each asset class.

D1.3 Network Development Strategies

We produce Network Development Strategies for specific geographic regions within our network area. Each region's Network Development Strategy provides information about emerging capacity risks and options to economically mitigate these risks. Each document is developed in accordance with our network augmentation planning criteria¹⁵⁴, and sets out:

¹⁵⁴ RIN Response – JEN network augmentation planning criteria paper.

- specific investment drivers and details of the network constraint(s)
- a summary and analysis of each credible option (including assessments of gross market benefits, net market benefits, and sensitivity analysis)
- the assessment methodology and assumptions (including information relating to economic planning, demand forecasts, asset ratings, Value of Customer Reliability, network outage rates, discount rates and cost estimates)
- a preferred option to mitigate an identified constraint.

D1.4 Asset Management Plan and Asset Investment Plan

The Asset Management Plan (and accompanying Asset Investment Plan) sets out an integrated approach to the activities undertaken by JEN to manage its asset lifecycles to ensure the efficient, JEN-wide delivery of optimum outcomes over the medium term.

The purposes of these documents are to:

- detail the operating environment and our customers' expected levels of service
- summarise risks and opportunities, contingency planning, and governance
- identify the type, number, condition and performance of JEN's assets, and their associated technical and commercial risks
- deliver on the JEN Asset Management Strategy and Objectives, including formal obligations and regulatory requirements and define the optimal and sustainable management of our assets in customers' long-term interests
- inform the capital and operating expenditure requirements set out in our Capital and Operational Work Plan
- ensure all investment decisions and strategies are aligned to the capital and operating expenditure objectives, criteria and factors as set out in clauses 6.5.6 and 6.5.7 of the National Electricity Rules.

JEN's Asset Investment Plan focusses on network assets while providing cross-references to more detailed strategies and plans for non-network expenditure such as non-network IT.

We develop our Asset Management, and Investment Plans consistent with our capital planning governance processes described in section 3. Once developed, JEN's Asset Investment team puts forward a complete annual program of capital works to the Executive General Manager Electricity Distribution, which is then subject to the approval of the Chief Financial Officer and Managing Director.

D1.5 Capital and Operational Work Plan

The purposes of the Capital and Operational Work Plan are to define:

- the activities JEN needs to carry out over the next two years to enable the provision of services to customers—namely the designing, constructing, operating, maintaining and supporting our electricity distribution network
- the scope of these activities and the various categories that are used to group and present expenditures (both capital and operating expenditure)
- the associated projects and budgets.

D2. Asset management system governance

D2.1 Structures, authorities and responsibilities

The responsibilities and authorities of key functions within the Jemena Group are defined through an organisational structure underpinned by position descriptions managed via Jemena's human resource management systems. Additionally, we maintain a comprehensive RASCI (Responsible, Accountable, Supportive, Consulted, Informed) mapping of these positions to processes (the identification of who is responsible, accountable, supporting, consulted and informed).

Structures, authorities and responsibilities relevant to the Jemena Group's asset management system—which JEN utilises—include the following:

- **Jemena Managing Director.** Accountable for the management of Jemena, and responsible for setting Jemena's Business Objectives, Vision and Values, under the guidance and support of the Board of Directors.
- **Executive General Manager Electricity Distribution.** Responsible for the management, maintenance and operation of JEN's assets, the EGM Electricity Distribution is actively involved in all aspects of the AMS, through the approval of documentation, communication of its elements, and the continual review of the system's outcomes.
- **Executive General Manager Gas Distribution.** Accountable for the Jemena Group's Asset Management System and chairs the Group-wide Asset Management System Review Committee (**AMSRC**), which has responsibility for the Asset Management System as a whole. Also develops Jemena's Asset Management Policy (which is signed-off by the Managing Director).
- **Asset Management System Review Committee.** Provides general and senior management with a forum to monitor and review the Asset Management System to ensure it is fit for purpose and delivers the Jemena Business Plan.
- **General Manager Asset Management (Electricity Distribution).** Responsible for ensuring the control of asset-related risks for JEN.
- **General Manager Strategy & Commercial (Electricity Distribution).** Responsible for securing funding for the planned project and program expenditure.

Further information is provided below on the roles and responsibilities of various committees within our asset management system governance.

Asset Management System Review Committee

The AMSRC is responsible for JEN's asset management system, including providing governance, ensuring alignment with business objectives and reviewing processes. Its functions include:

- directing the on-going development and implementation of the asset management system including alignment with other assets within the Jemena Group
- promoting the asset management system throughout the organisation while managing any interdependencies with corporate initiatives, strategies and objectives, developments, and business functions
- evaluating and ensuring the asset management system's sustained performance and continual improvement with respect to business policy, strategy, objectives, and planning
- implementing quality assurance via audits, including tracking compliance with legal and regulatory requirements and ensuring the completion of audit recommendation actions.

Management review of the asset management system is also completed through the AMSRC, the membership of which includes senior members from across the Jemena Group's asset management teams.

Operational forums

We have two operational forums which monitor our performance in terms of expenditure and service to customers:

- **Operational performance management forum.** This forum monitors the performance and progress of JEN's routine and non-routine capital and operating works (excluding IT) and KPIs, including facilitating business case approvals for projects as required.
- **Asset Performance Reviews.** This forum monitors the performance of JEN assets and the quality of service they deliver to customers, considering key performance indicators such as supply reliability, power quality and performance against guaranteed service levels.

Standardisation committees

Achieving our objectives relating to the asset performance and lifespan required of the equipment used within the distribution network requires a risk-based approach to the introduction of engineering changes and new technologies. Such changes in technologies and their potential opportunities, risks and impacts are considered through technical standards, which we maintain for our network.

We construct (or procure) new assets in accordance with our set of pre-defined technical standards to minimise the number of different assets and configurations across the network, thereby reducing procurement costs and operational and maintenance costs (including responses to plant failure), as well as minimising the number of spares which need to be held.

Standard development and modification is undertaken by several specialist areas within JEN that have responsibility for particular asset groups. For example, protection standards are developed by Asset Engineering's Protection and Control Group and the Primary Plant group develops primary plant standards. A system of standardisation committees has also been used for the development of standard designs, policies and procedures associated with the design and construction of primary plant and distribution system assets.

The standardisation committees comprise stakeholders from across JEN with technical expertise in asset management and planning, works delivery, construction and health, safety, environment and quality, to ensure a broad cross-section of input into standards development. These expert stakeholder committees collaboratively undertake standardisation activities in accordance with the JEN Standards Development and Modification Procedure. Risk assessments form part of the standard development process.

There are seven constituted standardisation committees. The level of activity in each area determines committee meeting frequency and meeting formality. Membership of the committees can vary depending on the issue under consideration and the expertise required. New committees can be established to address the particular problems if required.

The standardisation committees are as follows:

1. **Cables and Ground Mount Substations Standardisation Committee.** The focus of this committee is the standardisation and design of sub-transmission, high voltage and low voltage underground cable systems and indoor, ground mount and kiosk-type distribution substations. This includes the materials and equipment associated with these systems and the civil requirements for distribution substations.
2. **Overhead Lines Standardisation Committee.** The focus of this committee is the standardisation and design of structures and engineering systems associated with the sub-transmission, high voltage and low voltage distribution networks. This includes the materials and equipment related to these systems. The scope extends to customers' service connections to the network.

3. **Servicing Standardisation Committee.** The focus of this committee is the standardisation of the design and construction of overhead and underground services for customer installations and includes services supplied direct from substations.
4. **Zone Substations Primary Standardisation Committee.** The focus of this committee is on the design and construction of primary plant and facilities associated with zone substations and terminal stations that contain JEN assets. This includes the material and equipment associated with these installations and the civil and structural requirements.
5. **Protection and Control Standardisation Committee.** The focus of this committee is on the development and maintenance of secondary design standards for protection and control systems associated with the primary plant, network lines and cables. This includes the definition of the required protection schemes and the implementation standards.
6. **SCADA and Real Time Systems Standardisation Committee.** The focus of this committee is on the development of new technical policies, procedures, technical standards and material applications related to all Supervisory Control and Data Acquisition (**SCADA**) and Real Time Systems (**RTS**) issues. This includes the material and equipment associated with these installations.
7. **Substation and Distribution Automation Standardisation Committee.** The focus of this committee is on the development and maintenance of the substation and distribution automation design and installation standard. This includes the definition of the substation and distribution automation technical policies, procedures and implementation standards.

D2.2 Asset information management

Information is another key pillar of an effective asset management system and asset management decision making and activities. High quality and readily accessible information such as asset descriptions, performance measures, design parameters and the functional location is vital to the development of effective Asset Class Strategies and a range of other planning and operational decisions within our asset management system. We, therefore, maintain a comprehensive content management framework to facilitate the effective storage of electronic and non-electronic records.

Examples of asset information that may be required to facilitate effective decision making within the asset management system include:

- performance measures (depending on the criticality of the asset class and the selected lifecycle strategy, this may include failure rates, plant availability, plant defects, and corrective maintenance rates)
- asset identification numbers
- design parameters
- the functional location of the asset
- asset descriptions, including vendor details
- ratings, voltage level and operational requirements
- individual asset condition records
- commissioning dates
- operational expenditure
- capital expenditure
- regulatory reporting information

- risk management
- contingency and business continuity planning.

JEN uses several systems for managing its asset information. Maintaining an information management systems provides for common terminology for financial and non-financial information, enabling vertical information flows from senior management to operational areas, and horizontal flows between the asset management, financial management and risk management functions. This helps facilitate efficient communication and better integration of information sources to enable more effective planning, operations and reporting.

Jemena also maintains a content management framework, which is heavily informed by the asset management system. Records are either kept electronically or stored/archived as hard copies. Record retention timeframes are determined by either statutory or commercial requirements, or by individual teams, depending on the information contained within the records and how it is used for asset management decision making. The Human Resources and Health, Safety, Environment and Quality function within Jemena is responsible for our content management framework.

The electronic content management technologies we use to store and maintain content relevant to JEN include:

- HSEQ, a quality management system
- ECMS, our enterprise content management system
- Drawbridge, a drawing management system
- GIS, a geographic information system
- SAP, our business operations and customers relationship management system
- the JEN intranet team sites
- network drives.

For JEN asset management, all key asset management documents are managed, tracked, reviewed and continuously improved in accordance with the Key Asset Management Document Register. Project documents, asset drawings and geographical asset information are all managed through controlled electronic record storage systems.

D2.3 Change management

Effective governance and continuous improvement requires change to be implemented seamlessly and effectively to minimise the risk of unexpected outcomes. Internal or external changes affecting assets, asset management or the asset management system can impact JEN's ability to achieve its asset management strategy and objectives, which can have adverse consequences for customers and other stakeholders. As a result, planned changes require evaluation and management to mitigate potential issues before implementation.

Some of the key areas requiring change management include:

- continuous improvement to or changes arising from a review of asset management policy, the asset management system, Asset Management Strategy and Objectives, Asset Management and Investment Plans, or the delivery of the Asset Management and Investment Plans
- organisational structures, roles or responsibilities
- processes or procedures for asset management activities
- new assets, asset systems or technology (including obsolescence)

- changes in customers' expectations of the services we provide
- factors external to the organisation (including new legal or regulatory requirements)
- supply chain constraints
- demands for products and services, contractors or suppliers, and
- demands on resources, including competing demands.

D2.4 Asset risk management

Risk management is a further key component of an effective asset management system, by providing a structured process for identifying risks, identifying preventative actions or controls, and minimising the impacts if events do occur. Jemena maintains an organisation-wide risk management framework, and risk management activities within our asset management system are carried out in accordance with Jemena's Risk Management Policy, Risk Management Manual and Risk Management Guidelines.

Jemena maintains a team which is the organisation-wide custodian of risk management. The General Manager Risk is accountable for the management of corporate risks, while the Asset Risk and Assurance Manager is responsible for the management of risks specific to our electricity network.

We use our Risk Management Framework to develop individual risk matrices. Through this framework, risks are monitored and reported to the Jemena Leadership Team, Executive Risk Management Committee and Board Risk Management Committee.

Further detail on how risk management is explicitly applied in relation to capital planning and governance is provided in Appendix E section E5.

D2.5 Asset management system compliance

Jemena maintains a company-wide Compliance Management Framework to ensure compliance with regulatory obligations which relate to its operations. All of Jemena's material compliance obligations are recorded and managed within the Jemena Compliance and Risk System, which is designed to comply with Australian Standard 3806. We have several designated Compliance Program Managers who are responsible for maintaining this system and monitoring and reporting on Jemena's compliance in their respective areas.

Our compliance and safety procedures are described in our Electricity Safety Management Scheme (**ESMS**), with Electricity Safety Management Plans used to address key compliance risks. Our ESMS itself is reviewed quarterly by management at the ESMS Management Review Committee (chaired by the General Manager Asset Management – Electricity Distribution) and also at the Asset Public Safety Committee (chaired by the Executive General Manager – Gas Distribution).

Jemena's Leadership Team reviews summarised compliance management performance reports quarterly. Additionally, the Jemena Risk Committee monitors, reviews and evaluates the implementation of the Risk Management Framework, facilitating the development of a common, organisation-wide risk management approach by:

- implementing the framework
- sharing information with broad applicability across all areas of the organisation
- reporting on the progress of risk management framework implementation
- integrating risk management with business-as-usual activities.

D2.6 Asset management system audit

As part of our compliance management activities, we conduct systematic reviews of compliance through audits. The internal audit team is responsible for non-technical audits within Jemena and reports to the Audit Committee directly to ensure transparency. Internal audits are designed to assess the effectiveness of controls put in place as a consequence of a particular management system, which may include the following:

- **Jemena Compliance and Risk System.** As per the evaluation of compliance, all audit actions are monitored and tracked through the Jemena Compliance and Risk System, with formal reports generated monthly to track their progress. Once an action is closed, the internal audit team reviews the outcomes.
- **Asset Management System Review Committee.** In addition to the internal audit team's reviews, the Asset Management System Review Committee is responsible for reviewing the asset management system and its continued 'fit for purpose' status.
- **Audit and Risk Management Committee.** This committee governs and controls the internal auditing procedures, approves and prioritises regular audit action reports, and conducts completed action reviews.

Additionally, we conduct both internal and external audits to ensure safe fieldwork practices are maintained.

D2.7 Asset management system improvement

A key component of Jemena's process of continuous improvement involves ongoing performance monitoring, with corrective and preventive actions resulting from audits (technical and risk) and incident investigations being input into the Jemena Compliance and Risk System. Opportunities for improvement may also be realised from other internal and external sources. We have, therefore designed our asset management system to be readily adaptable to easily accommodate change by ensuring a simple and effective method for identifying improvements is available.

The role of the Asset Management System Review Committee

The Asset Management System Review Committee is responsible for determining opportunities and assessing, prioritising and implementing actions to achieve continuous improvement and reviewing its subsequent effectiveness.

This role includes:

- non-conformity and corrective action, particularly for emergency, failure and incident investigation
- examining trends in performance
- evaluation of compliance
- internal and external audits of our asset management system
- management review
- empowering employees to make suggestions
- change management.

Our approach to continuous improvement

As a further approach to continuous improvement, JEN actively seeks to acquire knowledge about new asset management-related technology and practices, including new tools and techniques. These are evaluated to

establish their potential benefits and risks, and if appropriate, are incorporated into both the Asset Business Strategy and individual Asset Class Strategies. Examples include:

- active participation in professional bodies and industry associations
- conferences, seminars, publications and journals
- benchmarking and technology transfer initiatives, and competitor check-ups
- engaging specialist organisations to provide advisory or audit services
- research and development
- consultation with customers and suppliers.

Appendix E

Capital planning governance and forecasting

E1. Capital project prioritisation

To ensure the efficient deployment of capital, JEN maintains a process to rank and prioritise projects proposed for inclusion in our program of capital works. The process provides a consistent approach to the evaluation of projects in relation to customer, risk mitigation, strategic and financial benefits, ensuring that all our investments are robustly evaluated to deliver a net customer benefit, to mitigate unacceptable risks and to deliver an expected return on investment that is acceptable to our shareholders. Given many of our investments are very long term in nature, this evaluation needs to account for long-term trends in consumer demands and consumer needs, growth in competing alternatives for customers and risk in future industry scenarios.

High-level steps involved in this process include:

- identifying all potential capital projects, including customer connections, asset replacement and network augmentation and non-network projects
- identifying mandatory projects, such as customer-initiated connections projects and projects commenced in the previous year
- defining projects sufficiently to enable their comparison with other projects
- identifying risks, net customer benefits, strategic benefits and financial benefits for each project
- ranking the projects in order of net customer benefit
- removing projects from the planning horizon where their net customer benefit is relatively low and not sensitive.

Our project prioritisation process also allows us to optimise our planning and maximise our delivery efficiency by considering:

- **Project coordination opportunities.** Where possible, we seek to coordinate projects which will occur at the same location, for example, a zone substation. Opportunities for such coordination may often arise for asset replacement projects, such as switchboard and secondary equipment replacement.
- **Constraints on timeframes for project commissioning or works.** We identify certain projects that must be completed before summer to ensure that network constraint are addressed before the likely period when peak demand will occur. This is most common for augmentation projects, such as new transformers, zone substations or feeders, the augmentation of sub-transmission lines or feeders, or establishing tie lines between feeders. Other types of projects, such as zone substation switchboard replacements, can generally only be performed during limited time windows (such as winter or spring, when peak demand is forecast to be lower), in order to limit the risk of supply disruptions for customers.
- **Long lead-time projects.** The replacement of some equipment at zone substations, such as transformers and switchboards, can require very long lead times—in some cases, the delay between placing an order for such equipment and it is delivered by the manufacturer can be 18 months. By factoring these lead times into our project prioritisation, we can ensure equipment is procured at a competitive price and the timing of the project's commissioning is optimal.

- **Identification and acquisition of land and easements.** We commence the identification and acquisition of properties and easements for zone substations well in advance of the construction of those assets, to ensure their availability and certainty of required planning permits and other approvals. For new zone substations typically needed in areas of greenfield urban growth, land may be scarce or in high demand. Additionally, community and stakeholder expectations are continually evolving, meaning we must consider factors such as visual amenity, electromagnetic field exposure, perceived reductions in neighbouring property values and environmental impacts of new zone substations. We are committed to the early and rigorous community and stakeholder engagement to provide transparency around the need for and benefits of proposed works. We, therefore, consider the potential benefits of securing land early in the subdivision process to avoid higher costs of developing a zone substation in an already developed area, weighed up against long-term forecasts of the required location of new demand and infrastructure.

This process ensures that our capital expenditure forecast is optimised and provides an integrated, coordinated and prioritised program of works aligned to our strategy and objectives, therefore delivering maximum benefits to our customers over the long-term.

E2. Our Project Management Methodology

Project management is an essential tool in the construction and management of our assets in line with our objectives and customers' long-term interests. To drive the prudent and efficient selection and delivery of capital projects, we have a standardised Project Management Methodology (**PMM**). Our PMM is structured around a seven sequential 'gates' which provide management focus at key points within the project's life, ensuring we deliver projects on time, within cost and to the required quality, in a safe, reliable and efficient manner. There are four phases within our PMM, illustrated in Figure E2–1.

Figure E2–1: Project Management Methodology phases



Projects officially commence with the issue of a Preliminary Project Mandate document, produced as part of pre-project planning and assessment activities. This ensures that we only incur costs undertaking detailed design for projects which are included within our plans and consistent with our asset management objectives. The first two stages are focussed on planning and design to a level of detail and certainty sufficient to obtain a final investment decision.

Following final investment decision, the project moves into the delivery phase, which entails any necessary further detailed design work, when a gate four certificate is issued to verify that the project is ready to commence construction in a safe and controlled state. Mobilisation, construction and commissioning activities can then proceed. Finally, the close phase ensures that high quality technical and financial asset records are produced and archived promptly, in accordance with regulatory requirements.

Products, outcomes and associated gates for each phase of our PMM are explained further in Table E2–1.

Table E2–1: Project Management Methodology phase descriptions

Phase	Product	Outcome	Gate
	Pre-project A supported infrastructure objective, as defined in the preliminary project mandate	Asset Investment Plan/Capital and Operating Works Plan updated to reflect the potential project	
Initiate	Option An articulated asset scope with delivery concept and constraints	Option confirmed	Gate 1
Plan & define	Scope definition A refined and validated, technically feasible design	Scope and requirements defined	Gate 2
	Plan Technical design, cost estimates and project delivery details sufficient to obtain approval	Detailed project plan	
	Approve An approved and funded project	Final investment decision and delivery approval	Gate 3
Deliver	Prepare & mobilise A finalised design and plan, ready for construction	Ready for construction	Gate 4
	Construct The project is fully mobilised and is in a ready state to commence the delivery stage	Project mobilised	
	Finish A functioning asset, ready for commissioning	Construction complete	Gate 5
	Commission A quality asset accepted by the owner as 'fit for service'	Project delivered	Gate 6
Close	Settle A fully documented asset and a completed project		
	Close A fully capitalised asset and a closed project	Project closed	Gate 7

Additionally, within our PMM, we have additional governance control relating to project size, which refers to the overall characteristics which may add complexity and risk to the management and delivery of the project. Before gates one and three, each project is rated as either a standard or complex project, based on our Project Sizing Procedure. Where a project has one or more specific areas of risk or complexity, it is rated as a complex project, and additional governance procedures may be included to manage these risks. For example, higher risk or larger budget projects may be required to undergo peer review before certificates being issued at various gates, be

required to have different types of project oversight or review committees, or be subject to different project reporting requirements.

E3. Cost estimation

Our capital expenditure forecast is comprised of individual cost estimates, which we have developed by applying the principles set out in the Jemena Cost Estimation Methodology.¹⁵⁵ We apply our Cost Estimation Methodology consistently to provide a robust estimating framework that employs the best available information to develop project estimates, depending on the nature and timing of the project. Our approach:

- provides accurate and consistent project estimates for all works, recognising the nature of the proposed work and its likely timing
- ensures that business cases and forecast programs have been estimated using appropriately sourced, realistic and efficient input data
- provides project estimates that account for safety, environmental and regulatory requirements
- identifies opportunities for innovation
- identifies the risks associated with the relevant works and ensure that these are communicated to Project Managers (for example the likelihood of encountering rock during excavations)
- ensures appropriate estimates are prepared at different stages of our Project Management Methodology
- ensures risk is treated appropriately, recognising that JEN undertakes a portfolio of projects and programs of work, and scope adjustment factors should be applied at the portfolio level
- ensures value for money for our customers
- ensures there is a formal change process if circumstances change for a project.

E3.1 Estimation techniques

We use a combination of two broad estimation techniques for capital projects—top-down and bottom-up. These ensure our project estimates are fit-for-purpose in the context of our Project Management Methodology (and its various gates) and the different planning horizons of our various plans, from our rolling two year Capital and Operating Work Plan to our seven-year Asset Investment Plan (and our regulatory proposal's forecast capital expenditure).

We employ three types of cost input in developing our cost estimates (which form part of our capital expenditure forecast), ensuring our estimates best reflect the actual efficient costs we forecast to incur:

- actual historical costs of completed projects of a similar scope
- input from experienced engineering, design and construction personnel
- quotations from external service providers.

Top-down estimation

Our top-down estimation technique relies on historical data from completed projects (or programs) of similar scope to estimate the cost of future projects. We maintain historical data using internal databases, with information sourced from:

- historical data from past projects

¹⁵⁵ Our Cost Estimation Methodology for network assets is provided as Attachment 05-06. Our non-network IT capital expenditure forecast has been developed using the methodology described in our Technology Plan. We employ a separate approach to non-network IT expenditure to reflect the unique characteristics of IT assets and the uncertainty created by the fast pace of technological developments and fact that the price review planning horizon for IT assets (up to seven years) can be longer than the lives of those assets.

- recent tender prices
- expected labour costs
- contractor prices.

Bottom-up estimation

Our bottom-up estimation technique involves our experienced engineering, design and construction personnel working with the design brief and functional scope of a proposed project to estimate the cost of each individual work package. We have estimating templates for major categories of work based on appropriate design and construction standards using bills of materials, standard task lists and base planning objects. In some cases, bottom-up project cost estimates may use quotes from third-party service providers—refer to section E6 for further information about our procurement process.

E3.2 Independent verification of our cost estimates

To ensure our cost estimates reflect the efficient costs of undertaking the activities represented in our capital expenditure forecast, we engaged independent expert AECOM to verify our costings for six of our proposed major zone substation projects.

To do this, AECOM prepared independent estimates for each project and compared these to our estimates and industry information such as actual costs and cost estimates to establish project benchmarks and ranges for typical industry installations. AECOM prepared its estimates on a bottom-up basis for each project based on our high level scopes, standards, specifications and normal industry practice, and considered local conditions and assumed network requirements when developing its estimates. AECOM's report states:

Overall, AECOM considers that Jemena estimates for the ZSS program of works is within the industry range and in accordance with expectations for projects of this type given the particular requirements and constraints of each of the projects.¹⁵⁶

This suggests that overall, our estimates have been produced on a reasonable basis and are likely to reflect the efficient costs of undertaking the activities required. A summary of these comparisons is provided in Table E3–1, and full details of their methodology and results are provided in our RIN Response – *AECOM ZSS Asset Replacement Programs Benchmark Report*.

Table E3–1: Summary of AECOM cost benchmarking findings

Project	AECOM finding	JEN estimate (FY22-26)
Coburg North zone substation switchgear and secondary equipment replacement	Similar to average costs within the accuracy range of the estimate	\$12.1M
North Heidelberg zone substation secondary equipment replacement	Similar to average costs within the accuracy range of the estimate	\$2.3M
Coburg South zone substation switchgear and secondary equipment replacement	Considerably higher than benchmarked average but within range of costs for these works. Factors attributing to higher cost include modular capacitor bank, high feeder costs and high building costs for this multi-level indoor zone substation	\$13.7M
East Preston zone substation additional transformer and 22 kV switchboard to facilitate conversion of 6.6 kV to 22 kV	Below industry average due to simple nature of this project	\$6.7M
Broadmeadows zone substation transformer replacement	Below industry average due to simple nature of this project	\$2.9M

¹⁵⁶ AECOM, *ZSS Asset Replacement Programs Benchmark Report*, January 2020, p. 1.

Project	AECOM finding	JEN estimate (FY22-26)
North Essendon zone substation secondary equipment replacement	Above expected range of costs	\$2.0M

E4. Business case assessments

We develop business cases to ensure that all capital investment decisions are prudent, efficient and best promote the long-term interests of our customers. Each business case uses a combination of technical, economic and financial analysis to determine the optimal solution and timing to address an identified need, and covers three key elements:

1. The project need, including:
 - Discussion of potential issues, such as deteriorating asset condition/performance or network capacity constraints, and the implications (impacts or risks) to customers arising from this issue
 - Relevant regulatory obligations that the project will address, such as new requirements for the provision of settlement data to the market operator
 - The project's objectives with reference to Jemena's Business Plan, strategic objectives, customer views and the National Electricity Rules' capital expenditure objectives¹⁵⁷
2. Options to address the project need, including:
 - Quantifying costs and risks of each option, including assessment of alternative project timings (e.g. deferral) and non-network alternatives
 - Assessing the costs and benefits to customers of each option
3. A recommended optimum solution that maximises net benefits to customers, including:
 - Financial analysis to demonstrate the project is financially viable and represents the option which will best promote the long-term interests of customers, consistent with the National Electricity Objective
 - Identification of mechanisms by which the project will be funded, including internal Delegation of Financial Authority approvals.

Factors and attributes considered in our business case financial and economic evaluations are outlined in Table E4–1.

Table E4–1: Business case financial and economic evaluation factors

Key consideration factor	Attributes
Capital inputs	<ul style="list-style-type: none"> • Capital investment • Profit or loss on the sale or disposal of assets
Non-capital costs	<ul style="list-style-type: none"> • Operating expenditure • Regulatory incentive scheme penalties

¹⁵⁷ NER cl 6.5.7.

Key consideration factor	Attributes
Benefits	<ul style="list-style-type: none"> Regulatory incentive scheme rewards Avoided/reduction in future operating costs Avoided/reduction in future capital costs Avoided supply risk List of unquantifiable benefits

E5. Risk management

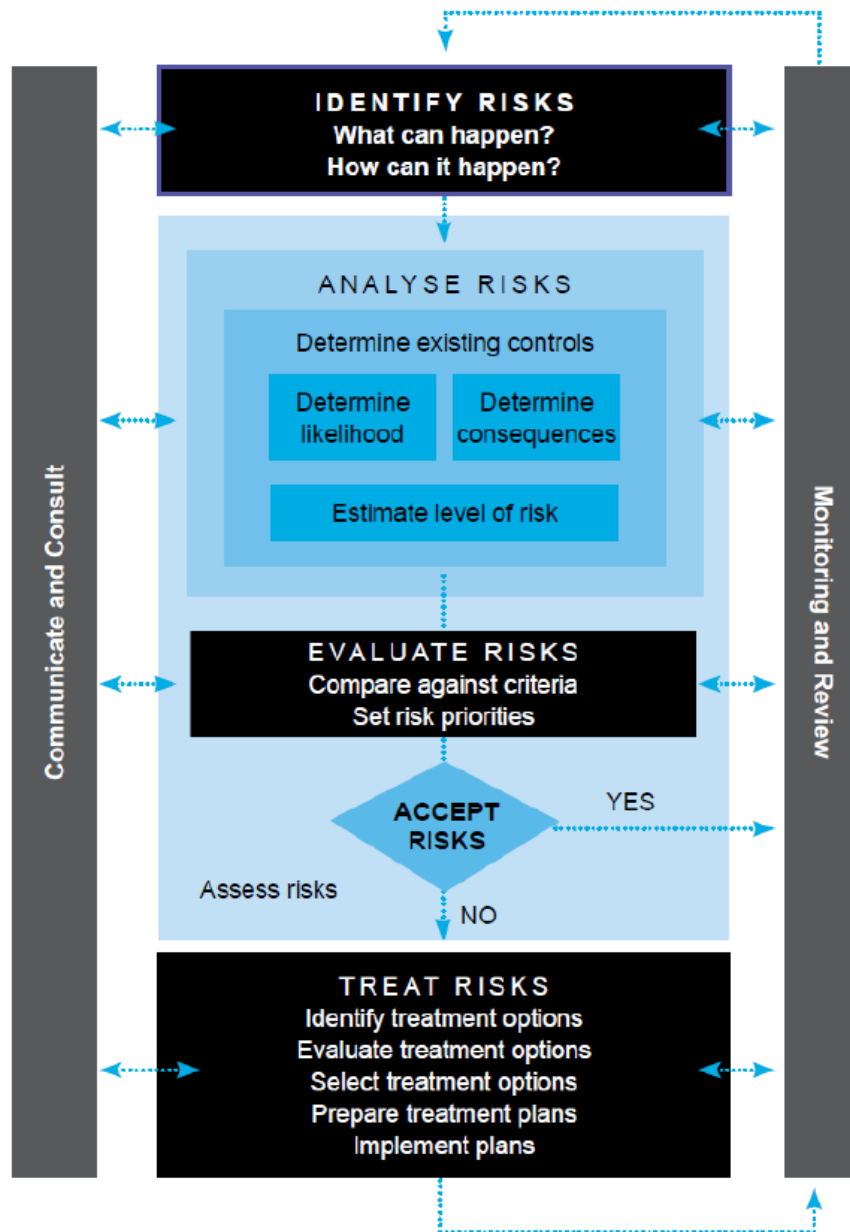
Effective risk management is an essential part of efficient capital planning and governance and is integrated into our organisation's culture. All risk management activity within Jemena is governed by the Jemena Risk Management Policy, summarised in Figure E5–1. We undertake risk management in conformance with AS/NZS 31000:2018. This involves the identification, evaluation and efficient management of all credible risks to ensure they are acceptably mitigated.

Risk management concepts feature as a factor in our planning and decision making at several levels, from strategy through to operations, with examples including:

- all significant projects undergoing a risk assessment phase, with risk management concepts influencing decision making on aspects such as contractor management
- risk management influencing our asset management planning, such as the development of our Asset Class Strategies
- risk assessments being carried out as a part of change management when there are significant changes to processes, equipment or materials
- field-based activities completed by contractors being monitored through targeted, risk-based audits.

We assess risks using risk criteria tables, with action plans then developed by a nominated risk owner to plan, monitor and report on the implementation of identified treatment actions. Identified risks are recorded in risk registers, with progress against actions usually being monitored at six-monthly intervals and more frequently in the case of critical tasks.

Figure E5–1: Jemena Risk Management Policy



Risk assessment framework

Once a risk is identified, we assess it by establishing a rating for its likelihood (Table E5–1) and consequence (Table E5–2), then combine these ratings using a matrix to determine an overall risk rating (Table E5–3) and risk management approach (Table E5–4).

Table E5–1: Risk likelihoods

Likelihood	Description	Guide
5 – Almost certain	Event is expected to occur in most circumstances	Will almost certainly occur once (or more) within one year, or >75% probability of occurrence, or has occurred recently and likely to occur again.
4 – Likely	Event will probably occur in most circumstances	Will probably occur at some time in the next two years, or 51%-75% probability of occurrence, or has a history of occurrence or could be difficult to control due to some external influences.
3 – Possible	Event should occur at some time	Might occur at some time within the next five years, or 26%-50% probability of occurrence.
2 – Unlikely	Event could occur at some time	Might occur at some time within the next ten years, or 5%-25% probability of occurrence.
1 – Rare	Event may occur only in exceptional circumstances	Improbable occurrence only in exceptional circumstances (i.e. may only occur in more than 10 years), or <5% probability of occurrence.

Table E5–2: Risk consequences

Consequence rating	Description	Financial		Operational	Health, Safety & Environment	Employee	Regulatory & compliance	Brand, reputation & stakeholders
		EBITDA / cashflow	Recoverable value					
Catastrophic	Potential disastrous impact on Group strategies or operational activities. Widespread stakeholder concern / interest.	> 5% of EBITDA (> \$50M). Imminent liquidity / cash flow problem – 100% utilisation of undrawn credit facilities & cash at bank.	> 5% or \$600M of Recoverable Value of Group Assets	Loss of electricity supply to 2 Zone Substations >24 Hrs or >15% Customers (49,000) >24 Hrs. Loss of gas supply to > 15% Customers (195,000). Business interruption for > 30 days (Group Assets).	1 or more fatalities (staff, contractors or member(s) of the public). Significant destruction of key internal asset or third party property. Harm to the natural environment and/or cultural heritage that cannot be remediated	Skill set/ capability of >35% of business critical roles lost within a 6 month period	Major regulatory restrictions and/or govt. interventions. Possible loss of licence to operate. Frequent regulatory or policy violations / breaches Major litigation, with a possibility of punitive damages. Significant fines, prosecutions and jail terms possible	Sustained and hostile public campaign. Reputation impacted with majority of key stakeholders. Sustained and critical stakeholder criticism
Major	Significant impact on Group strategies or operational activities. Significant stakeholder concern / interest.	3-5% of EBITDA (\$30M - \$50M). Liquidity / cash flow may be adversely affected – 100% utilisation of undrawn credit facilities	3-5% or \$360 - \$600M of Recoverable Value of Group Assets	Loss of electricity supply to > 2 % Customers (6,500) >24 Hrs. Loss of gas supply to > 1% Customers (13,000). Business interruption for 7 - 30 days (Group Assets).	Total permanent disability (staff or contractors). Multiple hospitalisations, permanent disability and/or life threatening injuries affecting member(s) of the public. Significant damage to internal assets or third party property. Harm to the natural environment and/or cultural heritage with remediation difficult (multi-year management)	Skill set/ capability of 20 – 35% % of business critical roles lost within a 6 month period	Regulatory investigations or govt. review. Some regulatory or policy violations / breaches. Litigation involving significant senior management time. Major fines or penalties and prosecutions possible	Significant adverse public attention and/or heightened concern from stakeholders. Reputation impacted with significant number of stakeholders. Significant stakeholder criticism/negativity
Severe	Moderate impact on Group strategies or operational activities. Moderate stakeholder concern / interest.	1-3% of EBITDA (\$10M - \$30M). Liquidity / cash flow may be affected – 50% utilisation of undrawn credit facilities.	1-3% or \$120\$360M of Recoverable Value of Group Assets	Loss of electricity supply > 1% Customers (3,200) > 24 Hrs. Loss of gas supply to > 0.1% Customers (1,300). Business interruption for 1 - 7 days (Group Assets).	Single permanent partial disability (staff or contractors). Medical aid required for member(s) of the public. Some loss of or damage to third party property. Harm to the natural environment and/or cultural heritage that can be remediated (<1 year management)	Skill set/ capability of 10-20% of business critical roles lost within a 6 month period	Regulator requires formal explanations & remedial action plans. Fines or penalties from legal issues, breaches / non-compliances	Persistent public scrutiny. Reputation impacted with some stakeholders. Some stakeholder concern/negativity
Serious	No material impact on Group, issues are dealt with internally.	0.1-1% of EBITDA (\$1M - \$10M). Liquidity / cash flow impact absorbed under normal operating conditions – 25% utilisation of undrawn credit facilities	0.1-1% or \$10\$120M of Recoverable Value of Group Assets	Loss of electricity supply to > 1% Customers (3,200) > 6 Hrs. Loss of gas supply to > 100 Customers or any contract customer. Business interruption for 1 day (Group Assets).	Medical treatment injury or lost time injury (staff or contractors). On-site first aid to a small number of member(s) of the public, lost time. Harm to the natural environment and/or cultural heritage requiring minimal remediation (at the time of impact)	Skill set/ capability of 5 – 10% of business critical roles lost within a 6 month period	Isolated regulatory or policy violations / breaches. Fines or penalties possible	Sporadic, adverse media/public attention. Limited adverse reputational impact. Minor stakeholder complaints
Minor	Negligible impact on Group, issues are routinely dealt with by operational areas	< 0.1% of EBITDA (< \$1M). Negligible impact on liquidity / cash flow.	< 0.1% or \$10M of Recoverable Value of Group Assets	Loss of electricity supply to <1,000 Customers up to 6 Hrs. Loss of gas supply to > 5 residential customers. Business interruption for a few hours (Group Assets).	Minimal impact on health & safety (staff, contractors or member(s) of the public). Harm to the natural environment and/or cultural heritage requiring no active remediation and/or able to self-remediate.	Skill set/ capability of <5% of business critical roles lost within a 6 month period	General regulatory queries. No violations / breaches, fines or penalties	Negligible media/public attention, reputational impact and/or little or no stakeholder interests

Table E5–3: Risk matrix

		Consequence				
		Minor	Serious	Severe	Major	Catastrophic
Likelihood	Almost certain	Moderate	High	Extreme	Extreme	Extreme
	Likely	Moderate	Significant	High	Extreme	Extreme
	Possible	Moderate	Moderate	Significant	High	Extreme
	Unlikely	Low	Low	Moderate	Significant	High
	Rare	Low	Low	Moderate	Moderate	Significant

Table E5–4: Risk management approach

Rating	Approach
Extreme	<ul style="list-style-type: none"> Requires immediate action. Highest priority risk to treat. Action plans prepared and usually implemented within 1 month. Status of risk should be monitored monthly. Monitored by Board/Board's Risk, Health, Safety & Environment Committee (RHSEC)/Executive Risk Management Committee (ERMC)/Leadership Team or Managing Director/Executive General Manager (EGM).
High	<ul style="list-style-type: none"> Requires immediate attention. Must manage with senior-level monitoring. Action plans prepared and usually implemented within 3 months. Status of risk should be monitored monthly. Monitored by RHSEC/ERMC/Leadership Team or EGM/General Managers (GM).
Significant	<ul style="list-style-type: none"> Requires management attention with a degree of priority. Action plans prepared and usually implemented within 6 months. Status of risk should be monitored every 6 months. Monitored by RHSEC/ERMC/Leadership Team or EGM/GM.
Moderate	<ul style="list-style-type: none"> Requires routine to periodic monitoring. Action plans prepared and usually implemented within 6-12 months where benefits outweigh the costs. Status of risk should be monitored at least every 6 months. Monitored by GM, escalated to EGM if risk consequence or likelihood is increasing.

Rating	Approach
Low	<ul style="list-style-type: none"> • 'Business as usual' – should not require much attention but should be reviewed at least annually. • Ongoing control as part of the management system. Risk facilitators to maintain a register of low risks and reassess annually. • Monitored by managers, escalated to GM if risk consequence or likelihood is increasing.

E6. Procurement

We maintain a robust procurement process which ensures technical suitability and cost-effectiveness of a purchase are the primary selection criteria. We use competitive tender processes when procuring the supply of goods and services, consistent with Jemena's Procurement Policy.

We apply a strategic procurement approach to developing, establishing and managing all sourcing and procurement contracts. This includes identifying procurement opportunities across the Jemena business, which drive benefits through the aggregation of demand and the standardisation of ordering and logistics processes. Strategic procurement is a proven method for managing higher value, higher risk or medium to long-term procurement activities and projects, and has been adopted as standard practice by numerous organisations in Australia and internationally.

Our Strategic Sourcing and Supply Chain team also provides support to the rest of the business in the development and implementation of contracts and service level agreements. We use equipment specifications based on relevant Australian or International Standards and have a standardised tendering process. We continually developments in the markets for the products and services we procure, and we re-evaluate our contracts periodically. We currently have period contracts in place for major plant items, listed below, and we have plans to re-evaluate all of these tenders within the next five years:

- underground and overhead cables
- poles
- crossarms
- distribution hardware (overhead terminations, conduits, clamps, fasteners etc.)
- electrical conduits and cover slabs
- distribution transformers and kiosks
- zone substation transformers
- zone substation protection and control equipment (including relays) and other secondary equipment
- meters
- zone substation and distribution switchgear
- switchboards
- insulators
- surge arrestors
- high voltage fuses.