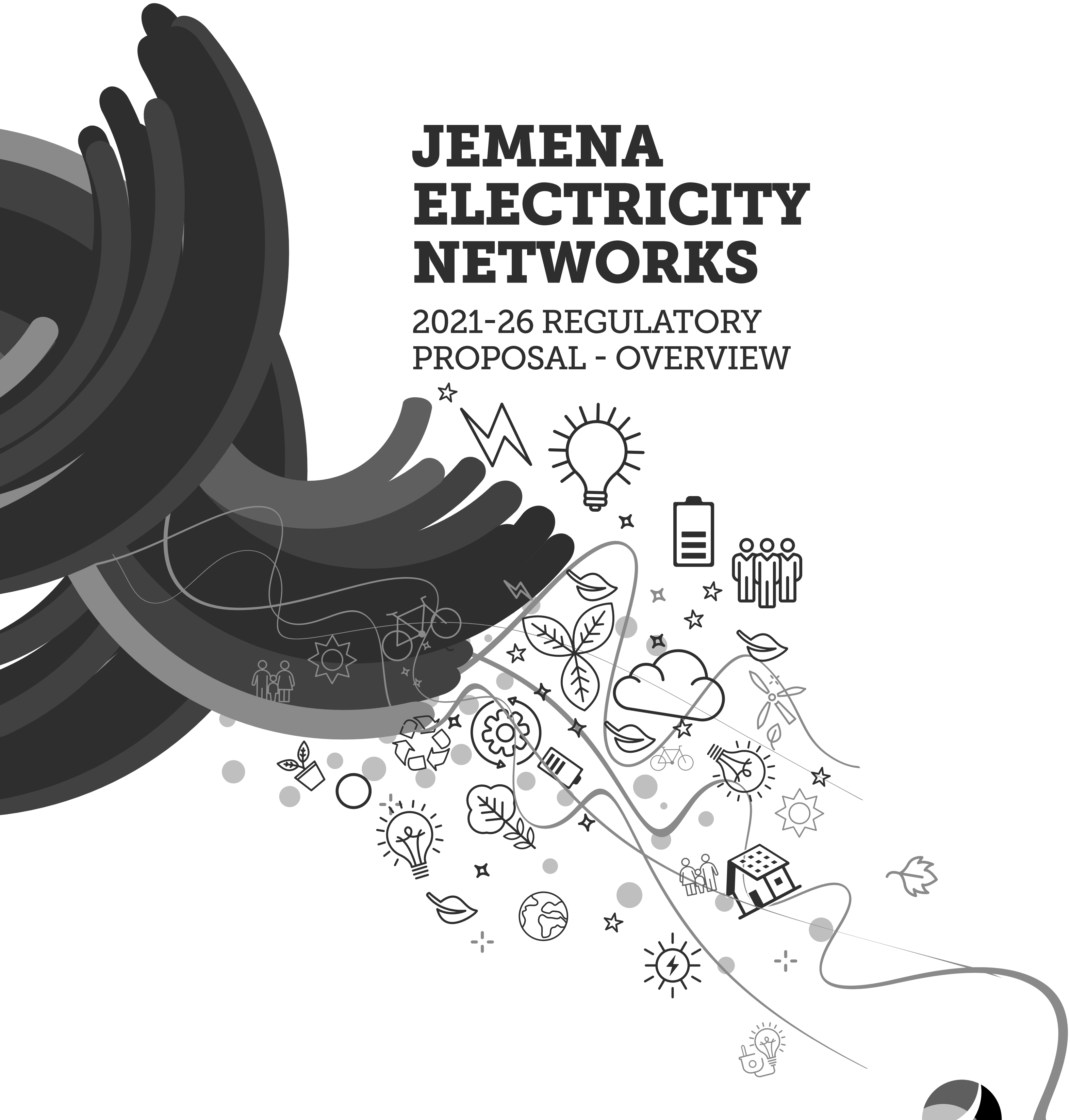
JEMENA ELECTRICITY NETWORKS

2021-26 REGULATORY PROPOSAL - OVERVIEW



Jemena
bringing energy to life

JANUARY 2020

JEMENA ELECTRICITY NETWORKS (VIC)
2021-26 ELECTRICITY DISTRIBUTION PRICE
REVIEW REGULATORY PROPOSAL (PROPOSAL)
COVERING 1 JULY 2021 TO 30 JUNE 2026 (NEXT REGULATORY PERIOD)

Monetary values are reported in June 2021 dollar values unless indicated otherwise.

OUR COMMITMENT

Message from the Board

Having joined the Jemena Board last year, I am pleased to see the comprehensive involvement our customers played in shaping the development of Jemena Electricity Networks' 2021-26 Proposal.

The members of the Board and I have been encouraged by the number of meetings, engagements and opportunities across the JEN distribution area which residents, small businesses, large industrial customers and all range of electricity stakeholders have had to speak directly with members of the Jemena team as we developed this Proposal.

As the unique distributor operating North West of Melbourne, it was important that we approached this review through the lens of the customer to fully understand the challenges they face. I believe the customer engagement process has allowed us to meet this challenge and made us a better company in the process.

By listening, hearing and thinking about what our customers have said, we are in a position to deliver a submission to the Australian Energy Regulator that has truly been shaped and endorsed by our customers.

Customers told us that their number one issue was affordability. This Proposal has taken this challenge into account and will help drive down network prices.

We also heard from our customers that they want us to innovate for a future so they can maintain their lifestyles. This Proposal outlines a number of digitally driven initiatives which are aimed at providing a reliable supply of electricity and creating a sustainable future for the community we serve.

As the Chair of the Board, I will be working with Board members, and everyone at Jemena to continue to work with customers to deliver the initiatives outlined in this Proposal.

Jiang Longhua
Chairman of the Board, SGSPAA
(parent company of Jemena)

Message from our Managing Director

We have listened to our customers and heard about the difficulties many of them are facing in making ends meet. Not only have electricity bills been rising, so has the cost of living and the cost of doing business.

We have also understood that many of our customers want a smarter, more efficient future grid that enables the community to share renewable electricity.

The response from our customers provides a strong direction that decisions being made today must consider the impact on the community as a whole, and future electricity customers.

In January 2019, we published a draft version of this Proposal for consultation to test whether we had accurately heard and understood the preferences of our customers, and to check whether we had appropriately implemented their feedback into our plans. I am pleased to say that during further consultation with our customers, they confirmed their support.

The Management Team, with guidance from the Board, has thought deeply about developing a Proposal that meets these expectations. We want to ensure that we deliver an affordable and reliable energy supply while facilitating a low emissions future for today's community as well as future generations.

Our Proposal is our attempt at continuing to enhance the long-term value for our customers. It intends to find the right balance between delivering lower prices now, and a sustainable future whilst maintaining reliability in electricity supply.

I'm pleased that our Proposal seeks to put downward pressure on electricity bills. Over the 2021-26 period and excluding the impact of inflation, a typical residential customer will save approximately $320 (14 per cent), a typical small business will save approximately $739 (10 per cent) and our large business customers will save an average of 9%.

Frank Tudor
Managing Director

SHORT ON TIME?

We are an electricity Distribution Network Service Provider (DNSP) and we are subject to economic regulation which is administered by the Australian Energy Regulator (AER), under the National Electricity Rules (NER).

Our revenue is approved in five-year cycles by the AER and, in the build-up to each new term, we submit a proposal to them which outlines our plans for the upcoming regulatory period—the five years from 1 July 2021 to 30 June 2026 (next regulatory period)—and how we expect to fund them. This document and related attachments constitute our Proposal for the next regulatory period that we will provide to the AER for their consideration.

The bottom line

Our Proposal includes a number of initiatives that will deliver reductions in our network prices over the 2021-26 period, continuing the trend we began in 2016. We also provide smart metering services to our residential and small business customers and are able to decrease these charges too.

These price reductions exclude the impact of inflation and are presented, as is other financial information throughout this Proposal, using the value of a dollar in 2021.

Our Proposal will result in bill decreases of 14% over the 2021-26 period, or $320 for a typical residential customer, when compared to their bills within the current regulatory period (see Figure X.1).

Figure X.2 provides a long-term view of a typical residential customer's network bill. With an expected network bill of $448 or $399 in 2021 dollars, customers in 2026 will enjoy their lowest network bill relative to their incomes in 15 years.

Figure X.1 Network bill impacts of our 2021-26 regulatory proposal

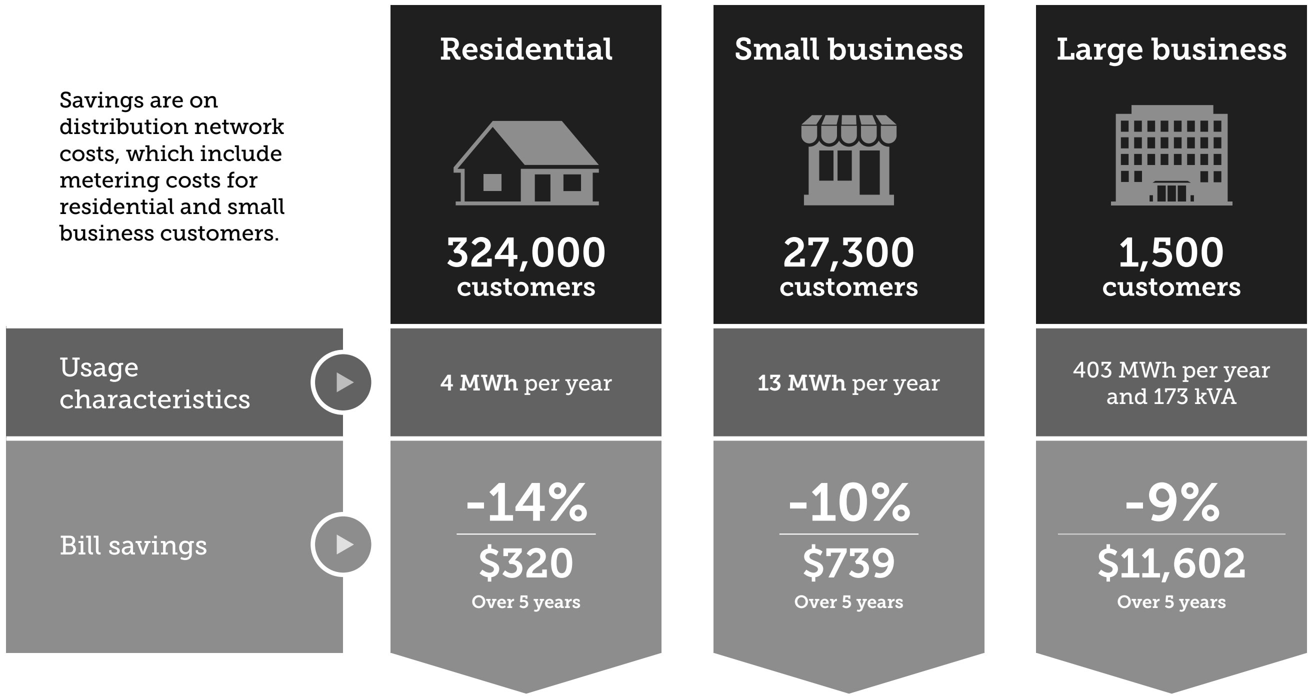
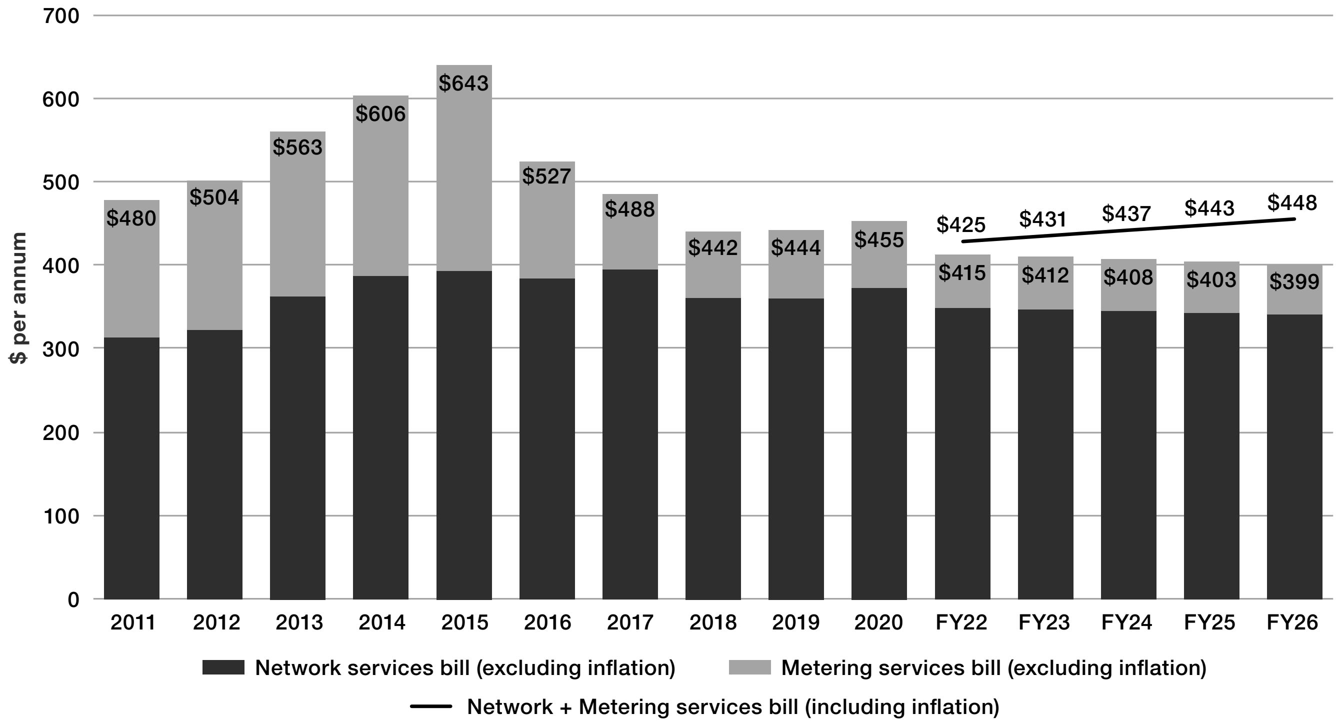


Figure X.2 Typical residential customer network services and advanced metering charges



Changing our regulatory years

For the next regulatory period, we are changing the years for which our proposal applies from a calendar year to a financial year. This is the reason why our charts in this Proposal report amounts on a different time basis.

What our customers have said

We embarked on the process of developing our next regulatory proposal with the following three objectives:

Figure X.3 Customer engagement objectives

To deliver on our objective to truly allow customers to shape our Proposal, we started engagement early, in 2017, with two key questions:

- How do customers want to engage?
- What topics do customers want to engage on?

We conducted several focus groups with customers to understand the best way to engage with them. After the early sessions, it was clear that retailers, large business customers and local councils had different needs to residential and small business customers. While the former wanted one-to-one sessions or, in the case of local councils, workshops to provide their feedback, it was clear that the latter group needed far more support, information and time to form opinions.

To really unlock the benefits of collaborating with our residential customers, what we needed was an innovative approach. Our customers' initial feedback confirmed that standard engagement processes tend to struggle to reach a broad section of the community, and time pressures lead to frustrations because of a lack of information about the subject, and give little chance to hear other views.

As the electricity network covers a relatively small geographical area, we felt the most effective way to engage with our customers was through a 'People's Panel'. This kind of approach is designed to be deliberative. It's a highly collaborative and engaging process held over several sessions and based on the concept of a jury. Critical to the success of this process, is the selection of a group that matches the demographic mix of the customer base, to form a 'mini-public', and this empowers them to make decisions confidently on behalf of our customers. For those who formed our People's Panel, it was a responsibility they took very seriously.

What struck us throughout our People's Panel process was how community-minded customers were. We found that while the affordability of electricity was a primary concern for all members of the community, the panel was also very keen to push towards a 'greener' grid.

From our meetings, large customers expressed interest in securing supply and lowering costs through collaboration and innovation. Our electricity retailers focused on tariff design, and local councils were focused on sustainability initiatives.

What we are proposing

The recommendations of our People's Panel have shaped our Proposal—in fact we have adopted them all. As a result, we believe we have developed a plan to deliver the network that our customers need to meet their long-term requirements.

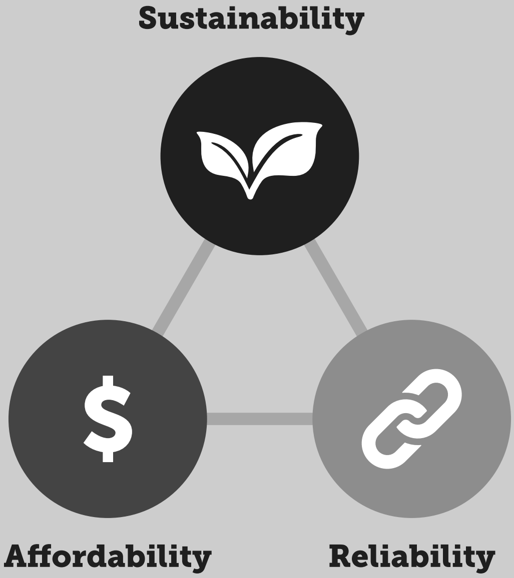
During our extensive program of customer engagement, we heard, loud and clear, that we needed to ready the network for increased feed-in of solar electricity and other renewable generation. As a result, our Proposal includes a number of initiatives that enable more feed-in to the grid from distributed energy resources (DER)—where the generation of power is decentralised and no longer needs to be transmitted over long distances; this includes solar panels and battery storage that sit on the customer side of the meter.

Over the long term, we will continue to embrace smart networks and the new and innovative technologies they bring. We also plan to leverage the infrastructure provided by the Advanced Metering Infrastructure (AMI) program to develop the kind of smart, robust and efficient network required to meet ever-changing customer needs.

What this Proposal means for our customers

Our Proposal is designed around delivering the kind of network our customers have told us they want.

Broadly speaking, the feedback from our customers was aligned to the energy trilemma of affordability, reliability and sustainability and, as such, we have devised a proposal that we believe delivers what our customers want, in a balanced and cost-effective way.



Affordability

We are committed to efficient expenditure. In our Proposal, we have clearly stated that we will continue to make efficient decisions for the future, like:

- Keep making replacement decisions based on the condition of assets, rather than to a fixed timescale.
- Spending money to prolong the life of existing assets rather than purchasing new ones, where it is cost-effective to do so.
- Proposing changes to network tariffs that reward customers who take steps to manage their usage.
- Investing in smart technology to monitor the grid and optimise spending.

Sustainability

We are committed to the sustainability of the network. The expected increase in the amount of DER across the electricity network in the coming years will benefit us, our customers and the environment. Our proposal includes the following:

- Investment to increase the amount of renewable energy that can be fed into the grid.
- Flexibility to use demand response to manage peak consumption across the network, where it makes economic sense.

Reliability

We are committed to delivering on our customers' expectation that we keep the electricity network as reliable as it is today. As such, we will be delivering:

- Improvements to the electricity network to detect faults early and protect customers from the risk of bushfires.
- Continuation of our long-term program to replace assets whose condition continues to degrade, and which pose the highest risk to safety and our ability to maintain our current reliability levels.

Customer views on our draft Proposal

In January 2019, we published a draft version of our Proposal (Draft 2021-25 Plan) for customer consultation. Our aim in publishing was to make sure we had properly understood what our customers told us, and that the decisions we propose to make about our services and prices, accurately reflect their priorities and long-term interests.

Once published, we resumed our interactions with customers who were part of our 2018 engagement program. This included customers who participated in our People's Panel, customer representatives from our Customer Council, and the Customer Challenge Panel. We aimed to understand whether or not we had accurately captured and applied the feedback we had received and whether they felt that our Draft Plan reflected customers' long-term interests.

To answer this question, we reconvened the Peoples Panel on two occasions—on the 14 and 23 March 2019—to again get feedback on our Draft Plan. Voting by our customers at these forums confirmed that 92% of participants were comfortable or very comfortable that the Draft Plan was in their long term interests; the remaining 8% were unsure and none were uncomfortable. They also confirmed that we had struck the right balance in the reliability, affordability and sustainability trilemma with a 96% vote being comfortable or very comfortable.

When releasing our draft Proposal, we specifically sought a separate submission from our customer council, independently compiled, to understand whether we achieved these objectives. We also received written submissions on our draft Proposal from Energy Consumers Australia (ECA) and the Customer Challenge Panel (CCP).

Given the feedback we received from our customers, we have not made significant changes since we released an early version of this document in January 2019. The updates we have made have primarily been to reflect new or updated data and information.

Deep diving into our proposal

Soon after releasing our Draft Plan, we asked stakeholders what they thought about our proposal, and if there were any areas they would like us to explain in more detail. In early March 2019, we held an open forum with the customer challenge panel, customer advocates and the AER where we addressed the areas of concern. The key topics we discussed included:

- detailing our information technology program and expenditure
- demonstrating our prudence and efficiency decision framework
- our Capex program
- the network of the future
- our proposed Opex
- and benchmark performance.

At the conclusion of the deep dive forum, the attendees said that they felt better informed and we committed to providing more information to make it easier to understand our proposal.

Revised timetable for a regulatory proposal

Soon after the two People's Panel sessions held in March 2019, a change in the regulatory year for Victorian electricity distribution businesses was announced. This change invariably meant that the timeline for submitting our regulatory proposal to the regulator would have to change, but we wanted to recheck whether our customers' views stayed the same.

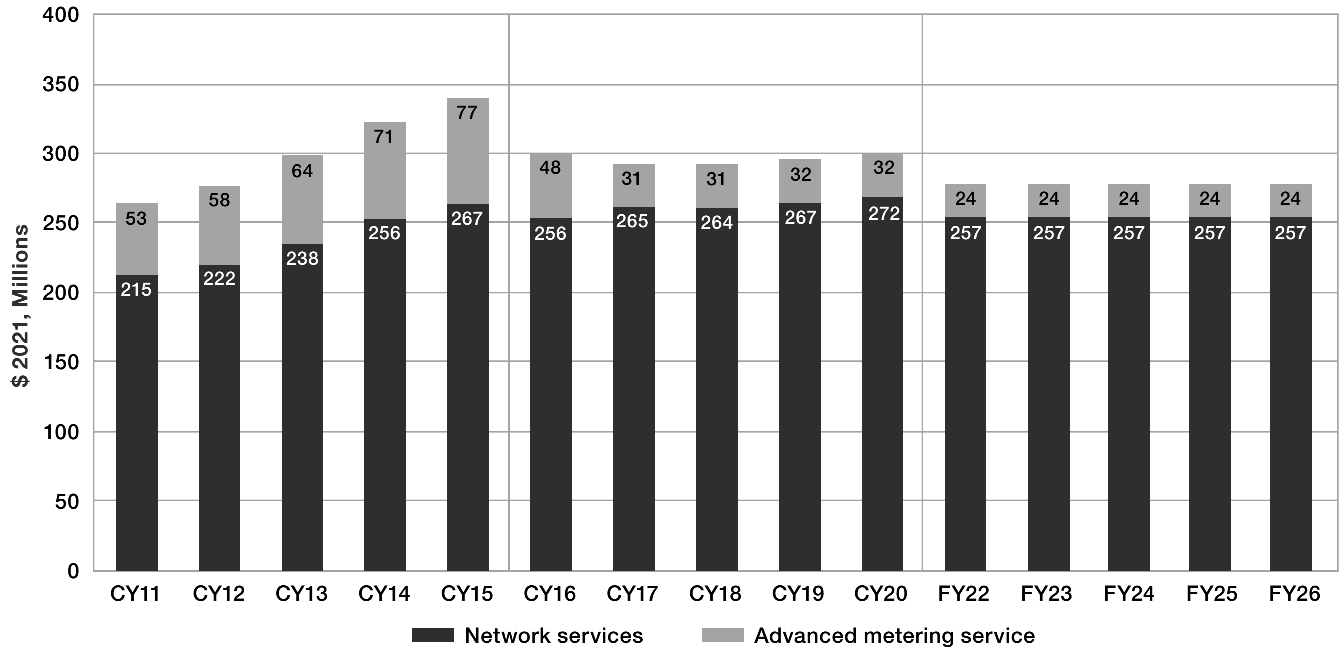
We reconvened the Peoples' Panel on 24 July 2019 to ask the question "would your recommendations change as a result of the delay in the regulatory period?" We took a vote on the question, and the result was unanimous; the Panel confirmed that their recommendations would not change.

To manage the change to regulatory year, we are developing two regulatory proposals, one that covers the period 1 January 2021 to 30 Jun 2021 (intervening period) and this Proposal which covers the five years between 1 Jul 2021 and 30 Jun 2026.

How much it will cost

To deliver on this Proposal we are seeking $1,285 million in network revenue–excluding inflation–over the next regulatory period, which represents a 11 per cent reduction per customer when compared to the revenue allowance the AER approved in the current regulatory period. We are also seeking $119 million in revenue to deliver advanced metering services to our residential and small business customers, which represents a 37 per cent reduction from the current regulatory period.

Figure X.4 Our total network and advanced metering revenue requirement



In developing this Regulatory Proposal, we use a building block model. Using this approach, we forecast our costs to work out how much revenue we require over the next regulatory period. We incur many expenses to run our business, and these can change over time, this means our revenues will go up or down relative to the changes in costs that we incur. In the next regulatory period, the following factors will have the most significant influence on changes to our revenue requirement:

- Operating expenditure will reduce due to the application of productivity adjustments and our transformation program but will be partially offset by increased costs for managing a larger network and once-off costs (see section 6.1 and 6.3).
- Changes in our accounting treatment—where we expense rather than capitalise overhead costs—will influence operating expenditure upwards in the short term, however, reduce in the longer term (see section 6.4)
- Changes to how we calculate tax will reduce the tax allowance (see section 7.1)
- Changes in the approach we use to calculate debt and the return to shareholders will reduce building block costs (see section 7.1)

The net impact of these changes results in an overall reduction, as reflected in the lower revenues required in the next regulatory period.

Benefits and risks of our Proposal to customers

Figure X.5 What benefits our Proposal delivers for customers

Improve **affordability and greater choice** through tariffs to manage bills

Connect over **37,000 new residential customers** and **500 businesses** in north-west Melbourne

Replace or reinforce over **7,500 poles** at the highest risk of failure

Refurbish degraded 1960s equipment at our two largest zone substations to reduce supply risk for **50,000 customers**

50 MWh of new battery storage capacity to the grid

Support the Victorian Government's **big build projects**

Provide over **70 MW of new renewable energy** generation with a platform to export

Streamline customer experiences when requesting services or information from us

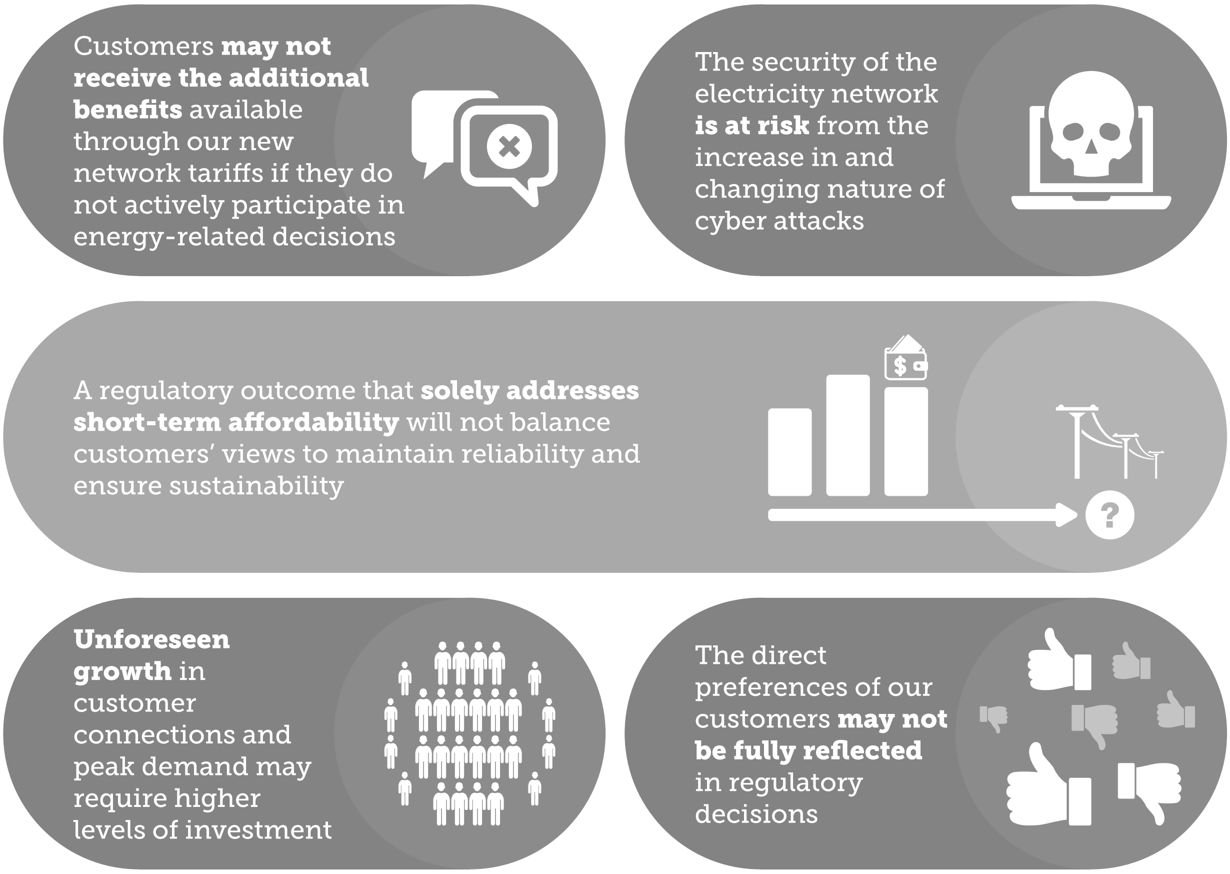
Invest in **new technology** which will help optimise the timing of future investments in the network

Provide more data to electricity market participants, in line with new obligations around five minute settlement

Enhance the security of critical IT systems in response to a heightened threat environment

Meet new supply requirements for major residential developments in Fairfield and other suburbs

Figure X.6 Risks of our Proposal to customers



Note: our Proposal seeks to mitigate against these risks to the extent possible.

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01 Background

1.1 About Jemena

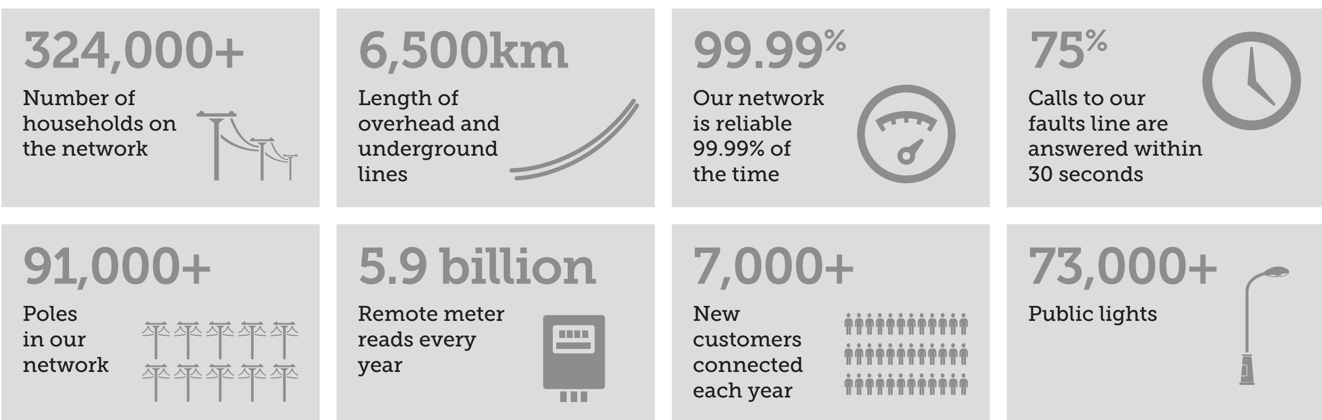
Our electricity network is one of five electricity distribution networks in Victoria. We are the sole distributor of electricity in north-west greater Melbourne.

Our role is to deliver electricity when our customers need it. We build and manage the infrastructure that transports electricity through more than 950 square kilometres of Melbourne's north-west suburbs, and provides energy to support businesses and critical infrastructure such as Melbourne Airport, which sits almost in the middle of our patch.

Anyone who is currently connected to the electricity distribution network in our area, is a customer of ours. We also connect new customers and provide distribution services to other groups like property developers, landlords and businesses of all sizes, from sole traders through to large energy consumers such as Melbourne and Essendon airports and hospitals. All in all, our distribution area covers approximately 12 per cent of the population of Victoria.

Figure 1.1 Our distribution area

Figure 1.2 Key characteristics of the electricity network



1.2 Why we are submitting a regulatory proposal

We are an electricity Distribution Network Service Provider, and we are subject to economic regulation which is administered by the Australian Energy Regulator under the National Electricity Rules.

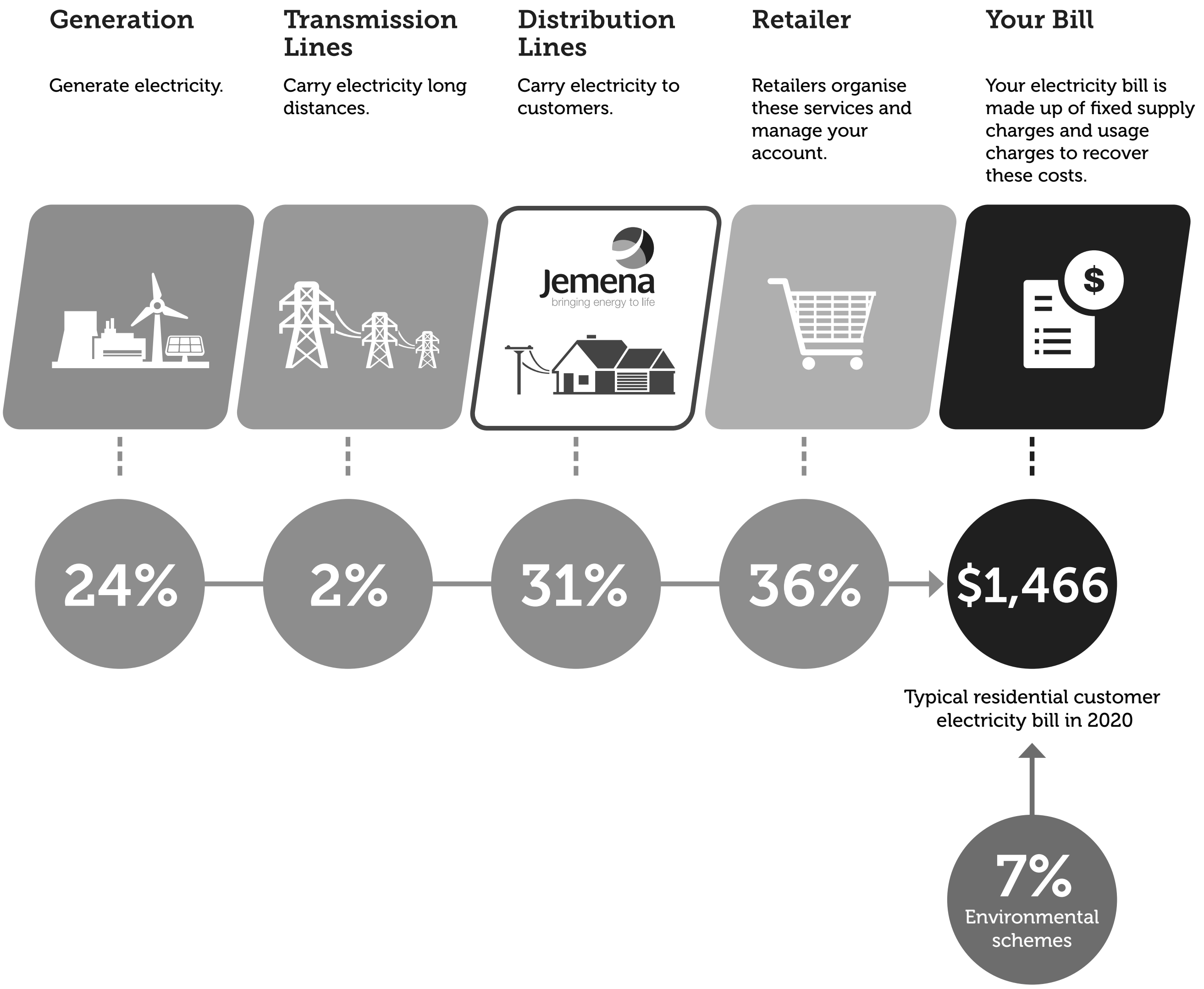
The cost of distributing energy across the electricity network is paid for through the network charges included in customers' electricity bills and, typically, amounts to around 31 per cent of the total.

Our revenue is approved in five-year cycles by the AER and, in the build-up to each new term, we submit a proposal to them which outlines our plans for the next regulatory period and how we expect to fund them.

We have prepared this Proposal for the next regulatory period, and have provided it to the AER for their consideration.

More information on the details of this Proposal can be found in Attachment 07-01. A summary of the data underpinning this proposal can be found in the appendix to this document.

Figure 1.3 Components of a typical residential electricity bill



1.3 Customer-focused regulation

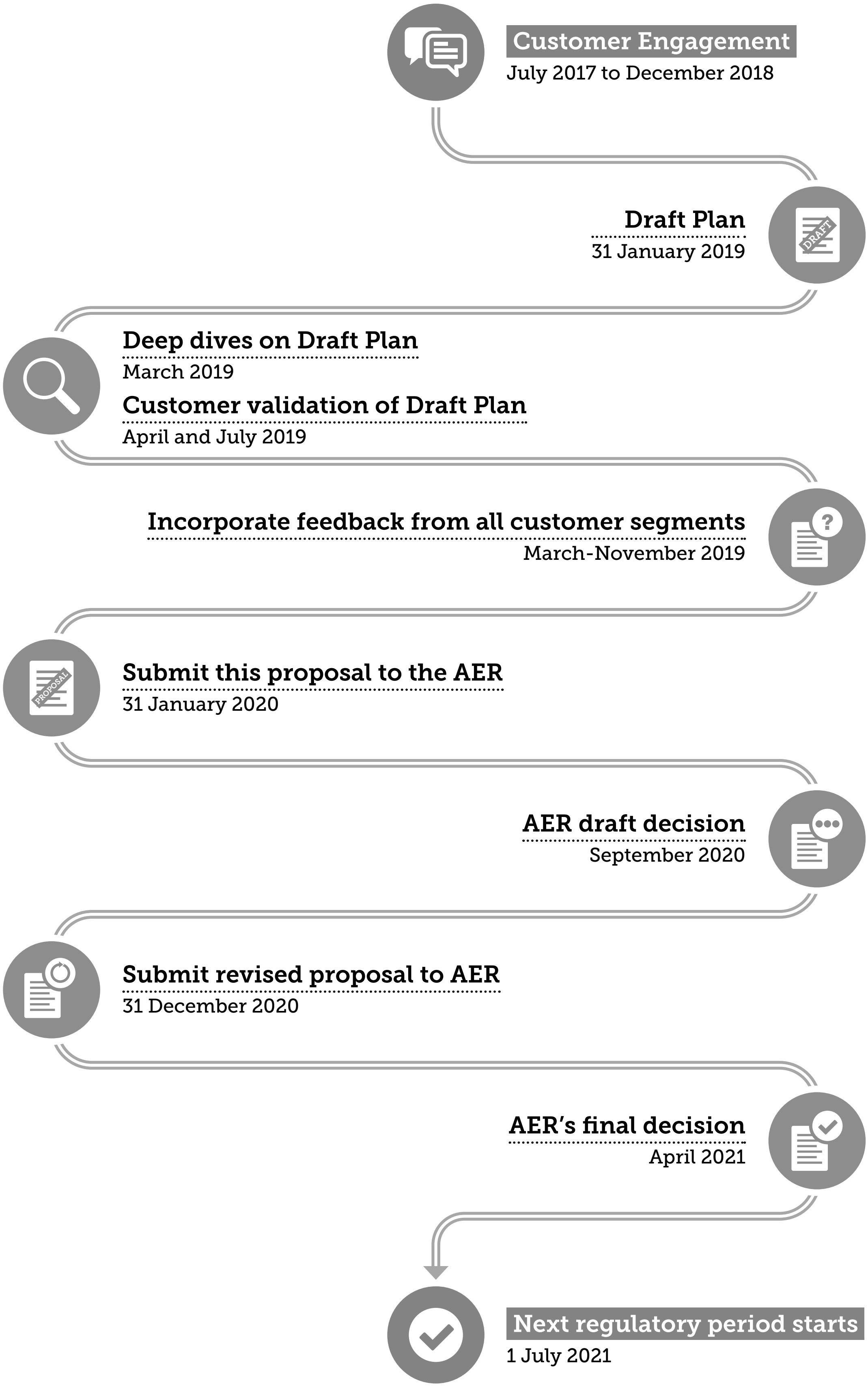
The AER regulates energy networks and markets. It must ensure the decisions it makes promote the long-term interests of customers.

As part of its five-yearly assessment of the revenue proposals from each of the electricity distribution network businesses, the AER considers—among other factors—the extent and quality of consumer engagement we have undertaken during the development of this Proposal. It also looks for evidence that our Regulatory Proposal reflects the outcomes of that process.

In the section on customer engagement, we will show how—in setting the expectation for our interactions with customers—we set ourselves the challenge to deliver an industry-leading engagement program based on well-established customer engagement principles.

1.4 The journey to approval

Figure 1.4 The journey to approval



02

Our customers **spoke** and we **listened**

Our customer engagement journey

Sunbury

Tullama

NOV 17

Household – Sunbury
18-35 age focus group
35-55 age focus group

Retailers and stakeholders
Joint Victorian DNSP tariff forum

Large customers – Broadmeadows
Council Forum
Key priorities – Engagement planning

Household segments – Moonee Ponds
Vulnerable focus group
Early adopters focus group
18-35 age focus group

Small and medium enterprise – Moonee Ponds
Focus group

Household segments – Coburg
Vulnerable focus group
Early adopters focus group
Over 55's focus group

Small and medium enterprise – Coburg
Focus group
Household – Coburg
35-55 age focus group

DEC 17

Customer Council Meeting –
Melbourne CBD

Councils –
Identifying council priorities

APR 18

Retailers and stakeholders
Joint Victorian DNSP tariff forum

Moonee Ponds

MAY 18

Councils
Streetlighting forum

Co

Customer Engagement in Numbers

87 **Contact hours** of engagement

13 **Focus groups** with stakeholders

9 People's Panel **sessions** held

7,400 visitors to JEN **website** yournetwork.jemena.com.au

17 External **contributors**

38 Jemena **facilitators & presenters**

3 **Network tours** for stakeholders

43 **Residential customers** on People's panel

319 Online **surveys** completed

10 **Board & Senior Management members** who attended

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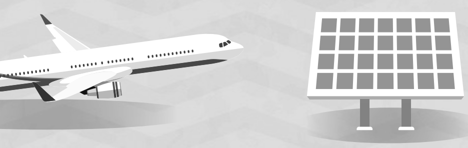


Broadmeadows

JUL – AUG 18

Household People's panel – Future Network Vision

Education

Testing price and service options

Validate our implementation

AUG – OCT 18

Large customers – Retailers

One-on-one discussions (face to face and phone)

SEP 18

Customer Council Meeting – Melbourne CBD

OCT 18

Councils Future network forum

NOV 18

Customer Council Meeting – Melbourne CBD

Austin Hospital

MAR 19

Household People's Panel Reconvened to seek feedback on Draft Plan

APR 19

Retailers and stakeholders Joint Victorian DNSP tariff forum

MAY 19

Customer Council Meeting, Melbourne CBD Updated engagement results

oburg

JUL 19

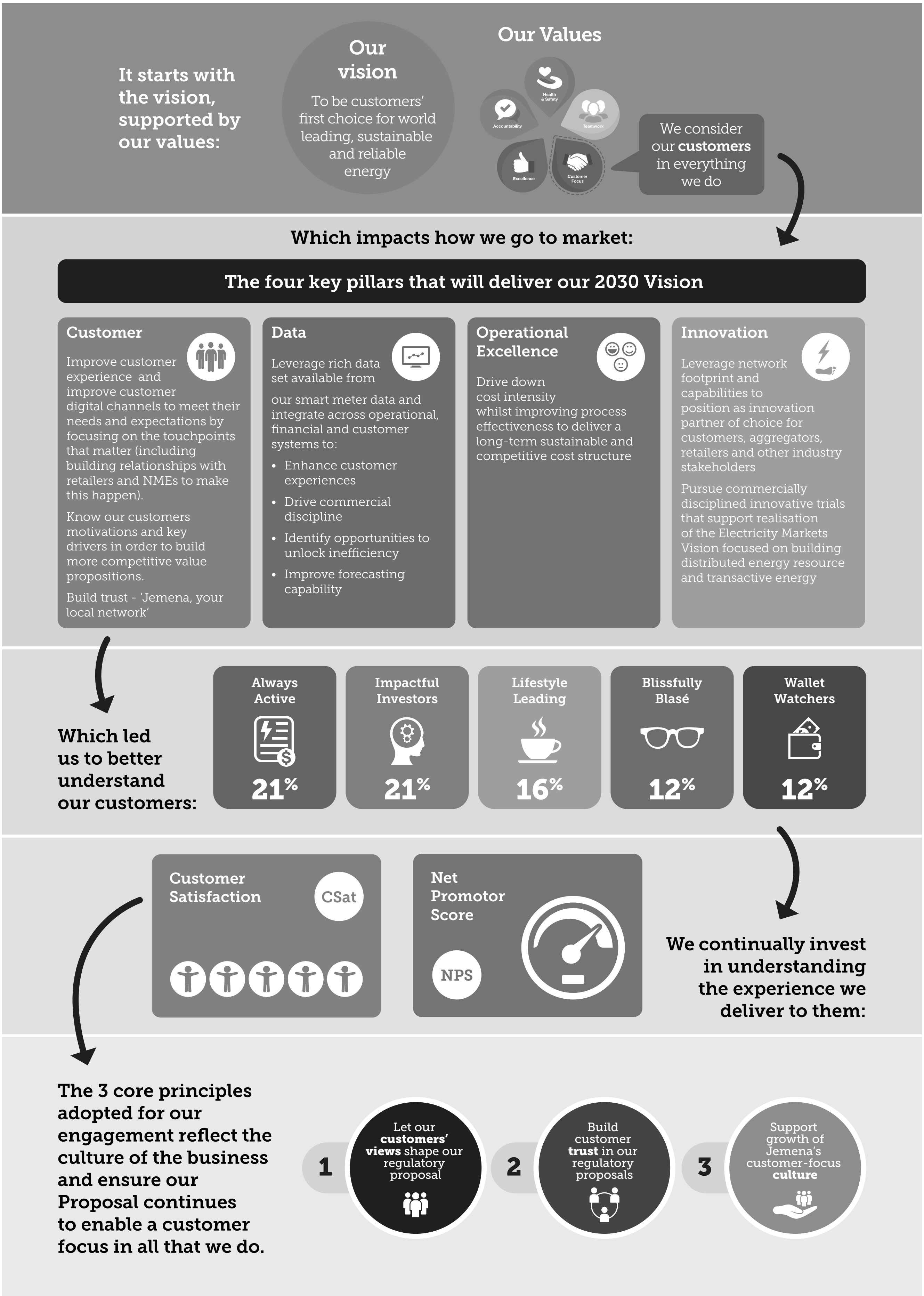
Household People's Panel Reconvened to validate recommendations

SEP 19

Large Customers Melbourne CBD – Energy Usage and Tariff recommendations

Customer Council Meeting, Melbourne CBD

Figure 2.1 Our customer story



2.1 Our customer and stakeholder engagement

As an organisation with a desire to continuously improve our culture that is centred around understanding customer needs, our Regulatory Proposal for 2021-2026 gave us a unique opportunity both to allow customers to help shape the services we offer and to inspire our team to improve outcomes for customers.

Figure 2.1 illustrates how our customer engagement has roots in the way we focus on customers on a daily basis. Jemena's vision is "To be customers' first choice for world-leading, sustainable, and reliable energy." To drive this through the organisation, one of our five values is Customer Focus. Through our continuous customer engagement activities, we seek to capture their views on our service, for example, through customer satisfaction surveys. Therefore the three core engagement objectives that we adopted for our Proposal reflect the culture of our business and the focus on customers in everything that we do.

Over the course of the journey, we brought the voice of customers into our business in an extremely powerful way and, in doing so, surpassed our expectations.

Our business is constantly adapting to meet the changing expectations of our customers. As a result, the organisation has changed significantly since our last proposal. Our leadership has created a vision that prioritises customer value through identifying and understanding our customers' needs, and so, in developing this regulatory proposal, we needed to deliver an industry-leading program of customer engagement. We set out three key objectives in Figure 2.1, and how we got here in Figure 2.2.

Figure 2.2 Customer engagement journey

To achieve our first objective and allow customers to shape our regulatory proposal, we recognised that we would need to do more than simply consult. We sought to involve and, where possible, collaborate with our customers, providing them with a greater opportunity to influence our proposal and shape it to meet their long-term interests.

To ensure our engagement process led to a proposal that our customers support, we endeavoured to provide customers with information that was as unbiased as possible. In other words, customers heard the full range of opinions on the subjects and issues we discussed, and had all the information available to allow them to make informed decisions—for example, we showed them the collective and individual bill impacts of different scenarios, in the short and longer-term, in a format that was easy to comprehend.

Finally, members of our team from disciplines as diverse as customer service and engineering, from support staff to Board members and our Executive Leadership team, participated in our engagement process. This allowed us to share the outcomes and views from customers more broadly throughout our organisation, and for our team to feel a sense of ownership of the outcomes, which they can apply in their day-to-day work. This has complemented our ongoing customer research programs that we have and continue to introduce.

2.2 Planning

Our planning phase was about learning the best way to engage with our customers. In November 2017, more than 18 months ahead of the deadline for our regulatory proposal to be submitted, we ran a series of 13 focus groups for residential and business customers, and spoke to local councils and retailers.

The following table shows what they said we needed to do to engage effectively with them.

Table 2.1 How our customers wanted to engage with us

Residential and small business customers	— Provide simple documents that are easy to understand. — Structure engagement in a way that is designed specifically for customers. — Start any discussion from the customer's perspective, not ours. — Take customers through a journey over multiple sessions.
Large business customers	— Preferred a one-on-one meeting rather than a time-consuming forum.
Local councils	— Workshops are a good way of engaging. — Structure events around key milestones in the regulatory process. — Engage with representatives from different teams in their organisations to obtain different perspectives. — Hold different 'streams' of events for different interest groups.
Retailers	— Stated a preference for individual conversations.

This information was invaluable during the execution of our formal engagement program and ensured that what we delivered met the needs of the whole community.

Table 2.2 The demographics of the people in our electricity distribution area

Category	Measure	Population profile	Participant target
Gender	Male	50%	24
	Female	50%	24
Age	0-14 years	N/A	N/A
	15-19 years	6.70%	3
	20-29 years	18.30%	9
	30-39 years	19%	9
	40-49 years	17.80%	9
	50-59 years	14.50%	7
	60-69 years	10.80%	5
	70-79 years	6.40%	3
	80 years and over	2.50%	1
Location	North west	6%	3
	Inner west	32%	15
	Inner east	11%	5
	North	13%	6
	Sunbury and surrounds	6%	2
	Broadmeadows and surrounds	5%	3
	Airport and surrounds	3%	2
	Inner north	24%	12
Cultural diversity	Born in Australia	79%	38
	Born overseas	21%	10
	Speak English at home	77%	37
	Speak language other than English at home	23%	11
Housing type	House own outright	27%	13
	Owned with mortgage	28%	13
	Rented	24%	12
	Other (census data: not stated, not applicable)	*21%*	*10*
Aboriginal or Torres Strait Islander		0.00%	0
People with a disability		12%	6
People with solar panels		13%	5

2.3 How we delivered on our engagement plans

Residential customers

Who we engaged with

After the early sessions with residential customers, it was clear that we needed to refine our approach to really unlock the benefits of collaborating with this group. Their feedback confirmed our view that standard engagement processes tend to struggle to reach a broad section of the community, and time pressures lead to a lack of commitment to learning about the subject.

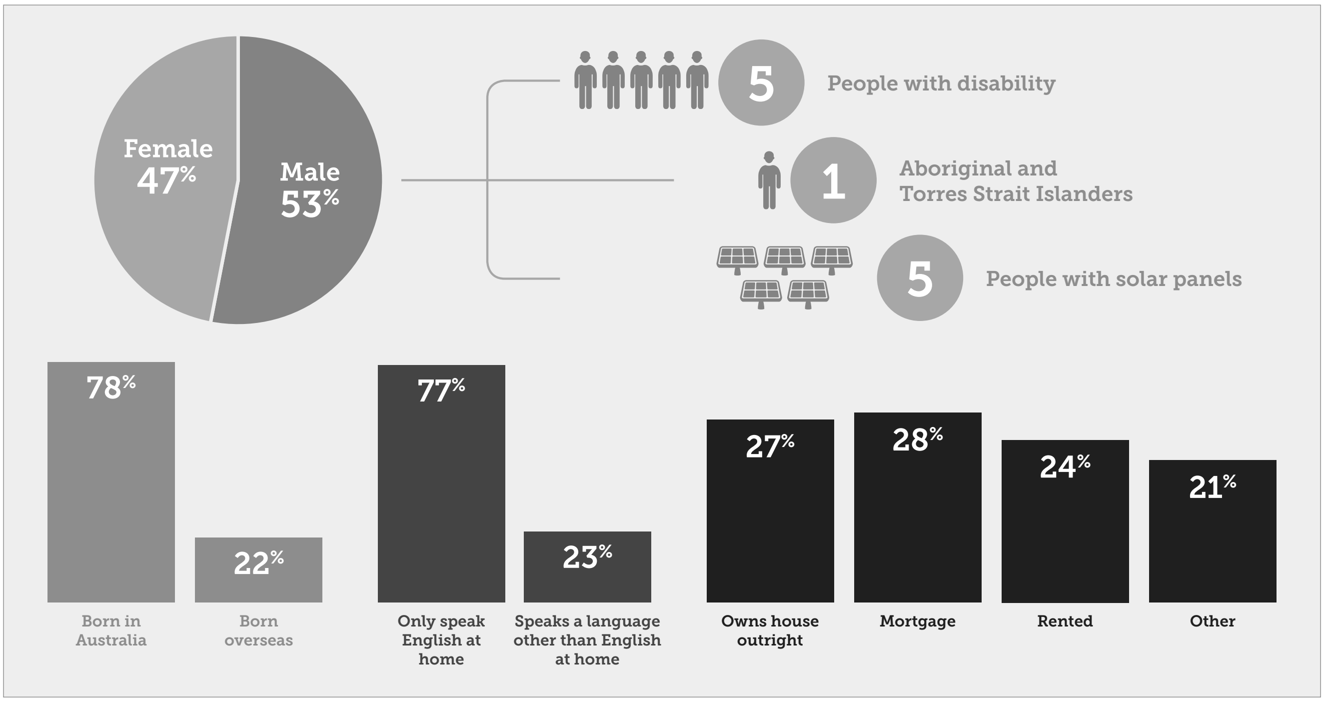
We needed a partner who knew how to engage community groups in complex topics, someone who would challenge us to deliver the right structure and resources to facilitate collaboration. This challenge led us to Capire. We chose Capire because they are a values-driven organisation dedicated to giving all community members a voice, had contacts amongst our community, and aligned closely with our values.

Because the electricity network covers a relatively small geographical area, we felt the most effective way to engage with our customers in a way that delivered what they had asked for, was a 'People's Panel' process.

This approach involved analysing the demographics of our community and then selecting 43 participants—a statistically valid sample of our customer base—who represented the diversity of backgrounds, views and experiences of people in our distribution area.

After an extensive recruitment program, we identified a strong representation of our customers that we provide electricity distribution services to.

Figure 2.3 People's Panel demographics



How the sessions were conducted

It was important to us that this engagement process was industry-leading and, when measured against the International Association of Public Participation (IAP2), that we improved on previous engagement activities we have undertaken.

Figure 2.4 IAP2 public participation spectrum

Increasing impact on decision

	Inform	Consult	Involve	Collaborate	Empower
Public Participation Goal	To provide the public with balanced and objective information to assist them in understanding the problem, alternatives, opportunities and/or solutions.	To obtain public feedback on analysis, alternatives and/or decisions.	To work directly with the public throughout the process to ensure that public concerns and aspirations are consistently understood and considered.	To partner with the public in each aspect of the decision including the development and the identification of the preferred solution.	To place final decision making in the hands of the public.
Promise to the public	We will keep you informed.	We will keep you informed, listen to and acknowledge concerns and aspirations, and provide feedback on how public input influenced the decision.	We will work with you to ensure that your concerns and aspirations are directly reflected in the alternatives developed and provide feedback on how public input influenced the decision.	We will look to you for advice and innovation in formulating solutions and incorporate your advice and recommendations into the decisions to the maximum extent possible.	We will implement what you decide.

Under the IAP2 guidelines, the process we ran sat in the 'collaborate' level of engagement on their spectrum of public participation. We worked with the People's Panel to develop a set of recommendations, which were then presented by a People's Panel representative to our Board for consideration.

The People's Panel was a deliberative process, a method of engagement in which participants take multiple points of view into account, and discuss issues and options, before forming their own view.

Throughout, we provided resources so the People's Panel could confidently participate in in-depth discussions about the future of electricity distribution services and network pricing.

The design of the process itself was largely informed by best-practice research and specialist consultant experience and knowledge. The following elements were included in the way we ran the People's Panel, notably the first four sessions, which are key elements of any deliberative process:

- Access to information and explanations about issues, including a commitment from us to answer all questions asked.
- Opportunities to hear opinions from independent experts, even if they differed from ours. To support this, we had representatives from many other organisations, including Simply Energy, Tesla, Energy Networks Australia. Their expertise and independence enabled the customers to gain deep insights into the industry and develop a trust in the genuinely open nature of the process.
- Hearing different experiences and views from other People's Panel members on the issues. We encouraged this through the lens of fairness. The People's Panel members were always respectful and empathetic. The People's Panel members valued hearing different views and, ultimately, reported changing their own views through the process. Where they considered decisions, the panel was mindful of their impact to individuals and the community as a whole, now and into the future.

Thirsty for information

The participants didn't hold back—in the first session alone, they asked 40 questions. In total, we had 90 questions which, by the end of the final session, we managed to answer in full. The complexity and maturity of the questions the People's Panel members asked—right from the beginning—energised us. We knew then that we had an engaged audience who would challenge us.

The Participatory Experience

Participants were involved in a variety of individual, small group and large group activities. They received information through our presentations, guest speeches, and through written and visual material online. Feedback was collected in a range of ways, including personal written responses, visual mapping, voting with stickers, and table-host notes.

- Adequate time and resources for People's Panel members to consider and discuss the issues before making decisions.
- Engagement activities in the sessions which were designed to provide participants with a range of experiences and learning, and give them an opportunity to weigh up the facts before forming an opinion.
- The provision of expenditure impacts arising from the recommendation so that participants could see the cost implications of their decisions almost immediately, and understand if other choices would have had different outcomes. This allowed them to change their views in real-time as conversations continued.
- Sessions were designed to be flexible in length, size and style of activities to accommodate the needs of all participants. The engagement of participants was strong from the beginning with most turning up to a voluntary information session, and it did not waiver with the full 43 completing the process. Panel members have already expressed an interest in returning to discuss this proposal and understand their impact on it.
- Support from the Board and Executive Leadership team was recognised by customers who felt that their recommendations were more likely to be considered as a consequence.

The People's Panel journey covered six sessions, including site visits, plus out-of-sessions homework. Each session was designed to build on the information and decisions made previously. On the final day, panel members were presented with a set of draft recommendations that they had co-created during the previous sessions. Before making a final endorsement of the recommendations, participants were shown the long and short-term impact of what they had recommended on customer bills, and were encouraged to share their perspectives.

> 'I learned so much and I can share this information with family and friends, so they understand energy on a different level.'
>
> **People's Panel Member**

The panel process delivered us much more than we initially expected. Yes, customers voted, and we were presented with a set of recommendations but, even more than that, we obtained deep insights into how customers feel, their values, and what drives their decisions.

What struck us through these conversations was how community-minded customers were, for example:

- choosing tariff types that benefited the whole community, even at personal cost;
- thinking of the next generation and wanting to make changes now, to ensure the network was ready to serve future customers in a sustainable way; and
- always looking for ways to help the less well off.

We found that while the affordability of electricity was a primary concern, they were also very keen to push towards a 'greener' grid.

> 'When is the next People's Panel?'
>
> **People's Panel Member**

Most of the sessions were also observed by representatives from the Consumer Challenge Panel and/or the AER staff.

Retailers and large business customers

Both of these groups had told us that their preference was to provide their views one-to-one, and as such, the engagement process was conducted in conjunction with account managers and operational teams.

Local councils

Local councils had told us they preferred regular forums or workshop-style events. To elicit their feedback, we arranged three council forums over an eighteen-month period. We also used our existing channels to engage with key contacts who were unable to attend the sessions.

Small businesses

This segment of customers is typically more challenging to engage with because of their diversity, limited resources and varying trading hours that make face-to-face interactions difficult to coordinate. Initially, we set out to run separate forums but had to cancel them. Eventually, we obtained the feedback we wanted by simply visiting customers at their business premises and completing a short survey. The twenty responses we received enabled us to gain insights on priorities, the impact of price increases and outages, and the adoption of DER.

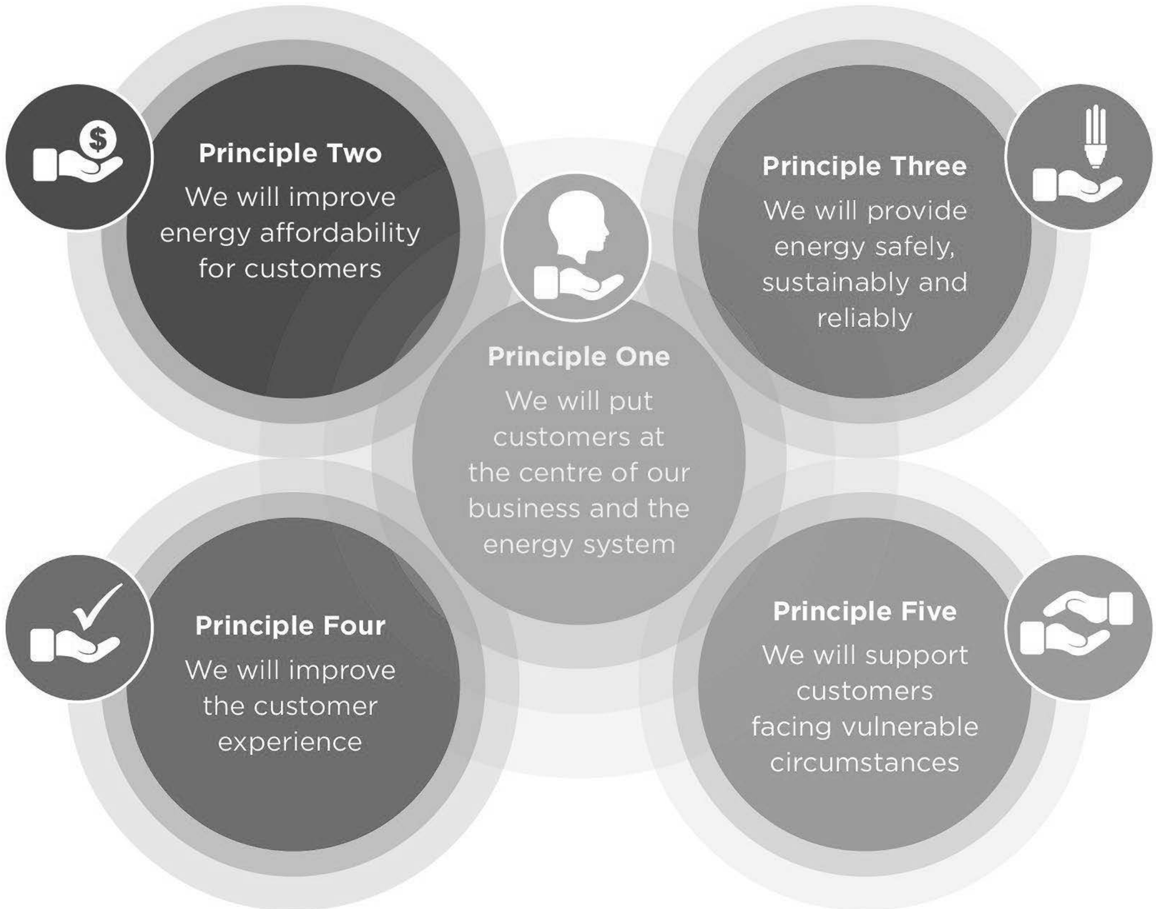
The Energy Charter

A first of its kind and a whole-of-industry initiative, the Energy Charter represents a voluntary commitment by numerous Australian energy companies to 'put customers first' by challenging and holding ourselves accountable for being customer focused and transparent in what we do.

"The Energy Charter is an opportunity for our industry to make sure customers are front and centre. We know a lot of homes and businesses are doing it tough and the Charter is an opportunity for us to work on ways to bring down customer bills, provide more clean energy and enhance network reliability."

Frank Tudor, Managing Director, Jemena.

Figure 2.5 Energy Charter Principles



We believe that our Proposal is closely aligned with the Energy Charter Principles:

- **Principle 1** – our Proposal is strongly centred on customer engagement and is supported by our customers.
- **Principle 2** – our Proposal delivers reductions in network prices.
- **Principle 3** – our costs are prudent and efficient, and seeks only that required to maintain the safety and reliability of our network.
- **Principle 4** – our IT capital program will allow us to keep up with evolving customer expectations in how they interact with us and the information we can provide.
- **Principle 5** – consistent with the feedback we received from our People's Panel, that we should support the vulnerable in our community, we will support initiatives that improve greater energy literacy to those who need it the most.

Our Customer Council

Our Customer Council was established in November 2011. Building strong working relationships with industry stakeholders, key customers and customer advocates through our Customer Council, ensures we have an ongoing source of the voice of the customer. The members of our Customer Council are shown in Figure 2.6.

As we developed our Draft Plan, we met with the Customer Council at each phase of our engagement program to seek their input and advice on both the structure and the content of our engagement program.

We also held individual and small group meetings with Customer Council members to hear their views and seek expert advice on specific topics related to our regulatory proposal.

Figure 2.6 Our Customer Council members

Residential & Vulnerable Customers
- Renew
- Kildonan Uniting Care
- Energy Consumers Australia (ECA)
- St Vincent de Paul
- Brotherhood of St Laurence
- Council on the Ageing VIC (COTA)

Small Business Customers
- Victorian Chamber of Commerce and Industry (VCCI)

Large Customers
- Energy Users Association of Australia (EUAA)
- Australian Industry Group (Ai Group)
- CSL Behring

Retailers
- Australian Energy Council (AEC)

Other Stakeholders
- Energy & Water Ombudsman - Victoria (EWOV)
- Australian Energy Foundation
- Northern Alliance for Greenhouse Action (NAGA)
- Emerging Technologies Research Lab at Monash University
- Clean Energy Council (CEC)
- Western Alliance for Greenhouse Action

2.4 Recommendations

Residential customers

During our initial consultation with residential customers, affordability was raised as a major concern.

As the People's Panel members explored a range of issues, they placed similar importance on maintaining the current level of reliability, and on providing access to information.

In the final session, participants were presented with 25 draft recommendations to consider. These came from activities previously undertaken, such as the results from votes in earlier sessions, or suggestions that had been made about how services could be improved.

There were two types of recommendation:

- Recommendations on topics that we must include in our regulatory proposal because they are things networks should take care of.
- Recommendations on electricity topics that networks do not usually address, but are relevant to customers, who believe networks could play a role in influencing outcomes.

After discussion and two rounds of voting, the People's Panel participants agreed on 25 recommendations to put forward to our Board for consideration. 22 of these received over 75 per cent support from the People's Panel, which is a super majority. The other three received majority support with 51 per cent or more of the vote.

Table 2.3 The recommendations were as follows:

The recommendations were as follows:

Recommendations on topics presented by Jemena
Recommendations to implement
Jemena should improve the information available to customers and the ease of access to smart meter data. This should be through: a. improving Jemena's portal b. adding additional services such as apps for smart phones.
Jemena should increase investment into energy literacy and awareness in the community by $330,000 per annum.
Jemena should investigate how customers could be provided with personal usage and bill information for different pricing structures.
Jemena should enable increased feed-in of solar (and other renewables) into the grid, by improving the performance of the grid through new technologies.
Jemena should improve their channels of customer service by increasing their services to include mobile apps and using simpler processes.
Jemena should invest in smart technology across the grid to ensure network equipment is not upgraded too early.
Jemena should maintain the number of outages as they are today–on average, each customer experiences one outage per year.
Jemena should maintain the length of outages as they are today–on average 51 minutes per customer.
Jemena should send SMS messages to all customers for unplanned outages. The message should include an estimation of how long it will take to fix the outage
Jemena should provide email or letter notifications about all planned outages. This should include accurate details of how long the outage will be and suggestions for how to manage the time without electricity.

Recommendations on topics presented by Jemena
Recommendations to implement
Jemena should work with retailers to create an opt-out process for notifications, so all customers can receive notifications via their mobile unless they choose not to.
The Panel believes that the Monthly Maximum demand pricing structure is the best for customers, so long as customers can opt out.
The Panel recommend that Jemena continue to explore using rebates to encourage customers to respond during times of need (for example hot days).

Recommendations suggested by the People's Panel
Jemena should advocate through its networks for:
Increased docking stations for Electric Vehicles across Jemena's network.
An impartial and technically accurate source of information for people who are considering installing solar. The information would include: a. what capacity can people legally have installed b. what are the tariffs available for solar customers, and how they impact bills c. what are the returns with the current feed-in tariffs d. how you best manage appliance use during the day to maximise energy generated from the panels.
New technologies that make the grid less carbon intensive such as renewable energy storage, efficient technologies and new housing development that enable efficient technologies.
Clearer information and engagement with customers about energy options so people know what is the best option for them, and whether it is worth investing in different technologies.
Support for vulnerable customers who may get left behind because they cannot take part in new technologies.

Recommendations suggested by the People's Panel
Jemena should advocate to the government and regulator for:
Government-supported energy literacy programs and educating customers about retailer deals
A bipartisan plan that responds to the energy crisis.
Provide bills in other languages.
Provide education resources about different supply and usage charges, and how charges are broken down.
Investigate pre-paid or bundled plans to eliminate bill shock or difficulty planning
Jemena should work with retailers to:
Simplify pricing rates to ease complexity and assist consumer choice.
Encourage retailers to keep providing paper bills for customers who want it.

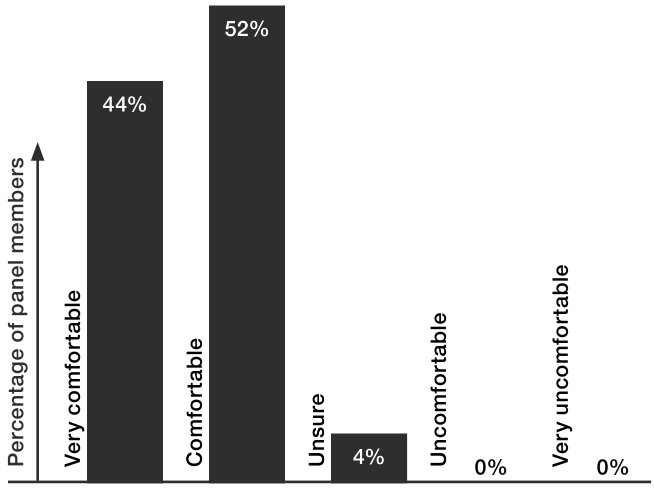
All of the recommendations on topics presented by the People's Panel have subsequently been adopted, and have shaped our Regulatory Proposal, except for the recommendation on outage notifications, we are commencing this activity in the current regulatory period. Throughout the remainder of this document, we will outline where and how we have incorporated these recommendations into our Proposal.

Returning to the People's panel

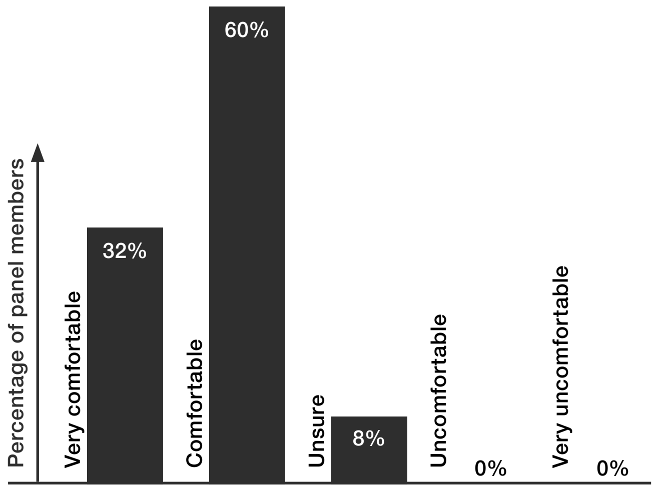
In line with the IAP2 core values, our plan was always to return to the People's Panel once our Draft Plan was ready, to ensure that we had accurately reflected their views and recommendations.

To answer this question, we reconvened the Peoples Panel on two occasions—on the 14 and 23 March, 2019—to again get feedback on our Draft Plan. Voting by our customers at these forums confirmed that 92% of participants were comfortable or very comfortable that the Draft Plan was in their long term interests. They also confirmed that we had struck the right balance in the reliability, affordability and sustainability trilemma with a 96% vote being comfortable or very comfortable.

How does (or does not) the Draft Plan sufficiently consider the long-term interest of Jemena's customers?



Does the Draft Plan strike the right balance in the energy trilemma for Jemena's whole customer base?



Change in the regulatory timetable

Soon after the two People's Panel sessions in March 2019, a change in the regulatory year for Victorian electricity distribution businesses was announced. This change invariably meant that our regulatory proposal would also have to change, but we weren't sure whether our customers' views would also change.

We reconvened the Peoples' Panel on 24 July 2019 to ask the question "would your recommendations change as a result of the delay in the regulatory year?" After outlining the issues, the rationale for the change, and allowing the panel members time to deliberate on the question, we took a vote on the question. The result was unanimous; the Panel confirmed that their recommendations would not change.

Customer advocates

When releasing our Draft Plan, we specifically sought a separate submission from our customer council, independently compiled, to understand whether we achieved these objectives. We also received written submissions on our Draft Plan from Energy Consumers Australia (ECA) and the Customer Challenge Panel (CCP).

To provide a clearer explanation of the key elements of our Draft Plan, we invited customer advocates to a deep dive session which was held in March 2019. In this session, we provided a detailed explanation of the key topics that advocates raised in their written responses to us.

Large business customers

The feedback from our large customers fell into three categories:

- **Affordability:** We should ensure the electricity network is operated as efficiently as possible and pass any cost savings on to customers, to put downward pressure on prices.
- **Reliability:** We should continue to operate at a high level of reliability.
- **Sustainability:** We should ensure the network has the capacity to accommodate growing demand from customers, including increased supply from DER. We should also invest to ensure that the impact of increased feed-in is minimised.

Our large customers are aware of many of the issues facing the electricity market and are keen to explore ways to address these challenges, particularly by feeding electricity into the network when it is most needed.

Electricity Retailers

The main focus of electricity retailers was on providing simpler network pricing to ensure tariffs were manageable for them, and for their end-customers. They expressed the view that, in order for new tariffs to be effective, it would be important for us to educate customers. They also wanted us to play a key role in enabling the new technologies and products that have emerged with the growth of DER.

Local councils

Local councils identified three main topics. They wanted to look at options for different commercial arrangements covering street lighting, as well as new light types and smart technologies. They were interested in how we could collaborate—for example through trials—on demand management, micro-grids, peer-to-peer energy trading, and other emerging technologies. Councils also asked for information on connection processes, so that projects we collaborate on could be better coordinated.

Our response to customer feedback

As a result of the feedback we received from our customers, we have not made significant changes to the draft Proposal that we published in January, as our proposal captured most of these requirements. The updates we have made have primarily been to reflect new or updated data and information.

Demonstrating incorporating customer feedback into our Proposal

In our Draft Plan, we outlined our preference to incorporate a customer service incentive scheme in the next regulatory period; at the time, we believed aligning shareholder interests with customer outcomes would be acceptable. Wanting to make sure the scheme was acceptable to our customers, we asked our People's Panel for their views. We did not get the support we thought we'd get with only 46% of the members saying they wanted the scheme. What they did tell us is that good customer service is just expected. With this response, we do not feel we can go forward with proposing a customer service incentive scheme, but it did tell us we need to keep investing in the customer interactions.

How these findings have helped inform our Proposal

At the end of the People's Panel process in 2018, the 25 recommendations were presented to our Chairman to take to our Board for consideration. After reviewing each—and having them validated through the reconvened panel sessions held in 2019—we have committed to adopting every one of the recommendations.

In line with the first strategic goal for the engagement process, these recommendations have shaped our Regulatory Proposal. Throughout the rest of this document, we have indicated where the actions we are planning for the next regulatory period are in response to these recommendations, and those made by our other customer groups.

Other customer feedback

We also took on board the feedback from other customer groups and retailers, and these too have been reflected in our Regulatory Proposal. For example, the debate about decorative poles amongst public-lighting customers resulted in a user-pays system, and we are looking to engage on more DER opportunities with business customers.

More information on our customer engagement activities can be found in Attachments 02-01 to 02-06

> 'Thanks Jemena for being open minded, willing to listen and learn from us, as well as being responsive to questions, comments and suggestions. Staff and senior leaders were well prepared and willing to come down to our level to pick up the messages and process them as efficiently and effectively as possible. You had a great sense of humour too!'
>
> **People's Panel Member**

03

The changing **energy market** and how we are **responding**

3.1 The current environment

The way the electricity market functions has a profound impact on customers' living standards, and even the viability of businesses and industries.

In recent years, electricity prices have risen considerably as a result of rising costs in the wholesale market, environmental policy measures and, in some areas, rising network costs. In turn, this has slowed the growth in demand for electricity and, at the same time, fuelled an increase in the take-up of DER.

Climate change, consumer choices, technology and policy changes have all added impetus to the transformation of the energy market in Australia, and electricity distribution businesses like ours constantly need to adapt and innovate in the way we service our customers and move electricity to and from their homes and businesses.

The ways in which the market will continue to evolve over the next two decades—including the costs of technology and fuel, the level of customer engagement, and the regulatory and policy response—remain a little sketchy, what is clear is that the energy system in the long term will be vastly different from that of today. Despite the uncertainty, in preparing this proposal we have recognised that—now they have been empowered by a range of technological, market and policy changes—customers are being presented with more and more ways to take control of their own energy needs. They are increasingly shopping around for better retail offers and looking to new technologies like battery storage, electric vehicles and smart grids to manage their usage and lower their bills.

With solar photo-voltaic (PV) systems becoming cheaper all the time, it is becoming more and more common for energy consumers to generate their own energy 'behind the meter'. That, in turn, has changed the way customers use the electricity network and, in response, we must continue to evolve.

For the next regulatory period, our aim is to continue to provide reliable energy and a platform that will facilitate innovation and support customers' choices about managing their own energy supply.

3.2 Longer-term megatrends

We consider there to be five global megatrends that drive electricity-sector transformation and are likely to fundamentally change the structure and function of the electricity system over the long term. They are:

Decentralisation

In the last decade, there has been a gradual decline in demand for electricity from centralised sources like power stations. Conversely, generation from, and consumption of, electricity from DER has increased.

Digitisation

It is impossible to escape the digital revolution. In the electricity system, digital technologies have enabled devices across the electricity network to communicate and share data that might be useful for both customers and the management of the grid itself. This includes smart meters, sensors, automation and other digital network technologies.

As well as the state-wide smart-meter rollout in Victoria, many networks are investigating—or have deployed—advanced metering infrastructure and smart grid technologies to digitise their networks as a way of reducing costs and realising financial savings.

Decarbonisation

The Paris Agreement entered into force on 4 November 2016. As of April 2018, 175 out of 197 parties had ratified the convention, including the Australian Government.

In light of this, and the expected retirement of the coal generation fleet between now and 2050, it is likely that significant amounts of variable renewable generation—whether large-scale or DER—will enter the electricity system in its place. From a network perspective, the more variable renewable generation sources that enter the system, the greater the need for flexible, dispatchable capacity to maintain system reliability and security. It could also mean there is a greater need for regions to be interconnected to balance and vary the generation mix. This could mean new transmission lines are required.

Electrification

With the introduction of high levels of renewables into the electricity system, the shift towards decarbonisation is likely to mean the electrification of activities that are currently fossil-fuelled. As generation shifts to more renewable sources, electrification is likely to be recognised for its environmental benefits by shifting end uses of electricity—including transport and heating—away from fossil-fuel sources. This shift is already happening in transport, where there has been a strong global increase in electric vehicles since 2010.

The rise of energy storage

Energy storage is made possible by the conversion of electricity into other forms of energy that can be stored. The cost of battery storage is rapidly declining and likely to continue to decrease. Australia is one of 8 countries expected to see the highest uptake of battery storage in the coming years.

3.3 So how will we respond to these megatrends?

The timing of each of these trends is not clear; equally, the impacts to our business and the way we work is also unknown.

Our strategic response

We are responding to these challenges by building a more commercial and competitive business and delivering fair outcomes across the communities we serve. Key to this is our vision to maximise the sustainability of our electricity network by connecting customers to the grid of the future.

We can look to other Australian businesses and the emergence of trends internationally to predict the extent of changes to the electricity network, but there is no certainty, and pre-emptive investment could be wasted. Of course, the way we work could also be impacted by the megatrends and the regulations that define our role in the electricity market we operate in.

Figure 3.1 Our strategic response

Customer

Improve customer experience and improve customer digital channels to meet their needs and expectations by focusing on the touchpoints that matter (including building relationships with retailers to make this happen)

Know our customers motivations and key drivers in order to build more competitive value propositions

Build trust - 'Jemena, your local network'

Data

Leverage rich data set available from our smart meter data and integrate across operational, financial and customer systems to:

- Enhance customer experiences
- Drive commercial discipline
- Identify opportunities to unlock inefficiency
- Improve forecasting capability

Operational Excellence

Drive down cost intensity whilst improving process effectiveness to deliver a long-term sustainable and competitive cost structure

Innovation

Leverage network footprint and capabilities to position as innovation partner of choice for customers, aggregators, retailers and other industry stakeholders

Pursue commercially disciplined innovative trials that support realisation of the Electricity Markets Vision focused on building distributed energy resource and transactive energy

The changing role of the distribution network

As our society progresses towards a decarbonised future, the electricity system is changing and, as it transforms, so too does our role as an electricity distributor. Where we have traditionally been considered a relatively simple link in the supply chain from large-scale fossil-fuel generators to customer loads, the distribution businesses of the future will need to serve a far more complex environment. Our network will be one in which a significant proportion of generation originates from customers and flows back up the network, and where a multitude of customer devices are seeking to connect to, and interact with, the electricity system.

The transition to this new role will be heavily influenced by customers, governments and regulators, as well as other changes in the external market environment.

With a changing role imposed upon us, we are working to pre-empt the transformation, minimise the impact and embrace the opportunities that it presents. We see that greater dependence on data and communications will be necessary, and our interactions with markets will be greater. To accommodate this, we will be investing in digitisation technologies—such as IT platforms and analytics capabilities—to adapt to the growing expectations of the network business.

Network 'Hosting Capacity' for distributed energy resources

If the electricity network doesn't have the spare capacity to receive electricity that is being fed-back into the grid from household solar systems, there are impacts to the reliability of power supply. The voltages start to increase and transformers can start to fail. This increases the pressure on the assets in the network, and triggers increased costs to replace them.

The other impact is to customers themselves. If a solar PV system turns off, the amount of electricity fed into the grid is less than it could have been, and the customer loses money that they could otherwise have earned through feed-in tariffs.

Over the next regulatory period, we plan to invest in new technology that will allow us to better monitor, manage and plan the network, to deal with ever-increasing levels of DER. This will allow us to quantify the levels of solar PV, storage and—over the long term—respond to the megatrends under different operating configurations with sufficient lead times, and not too early.

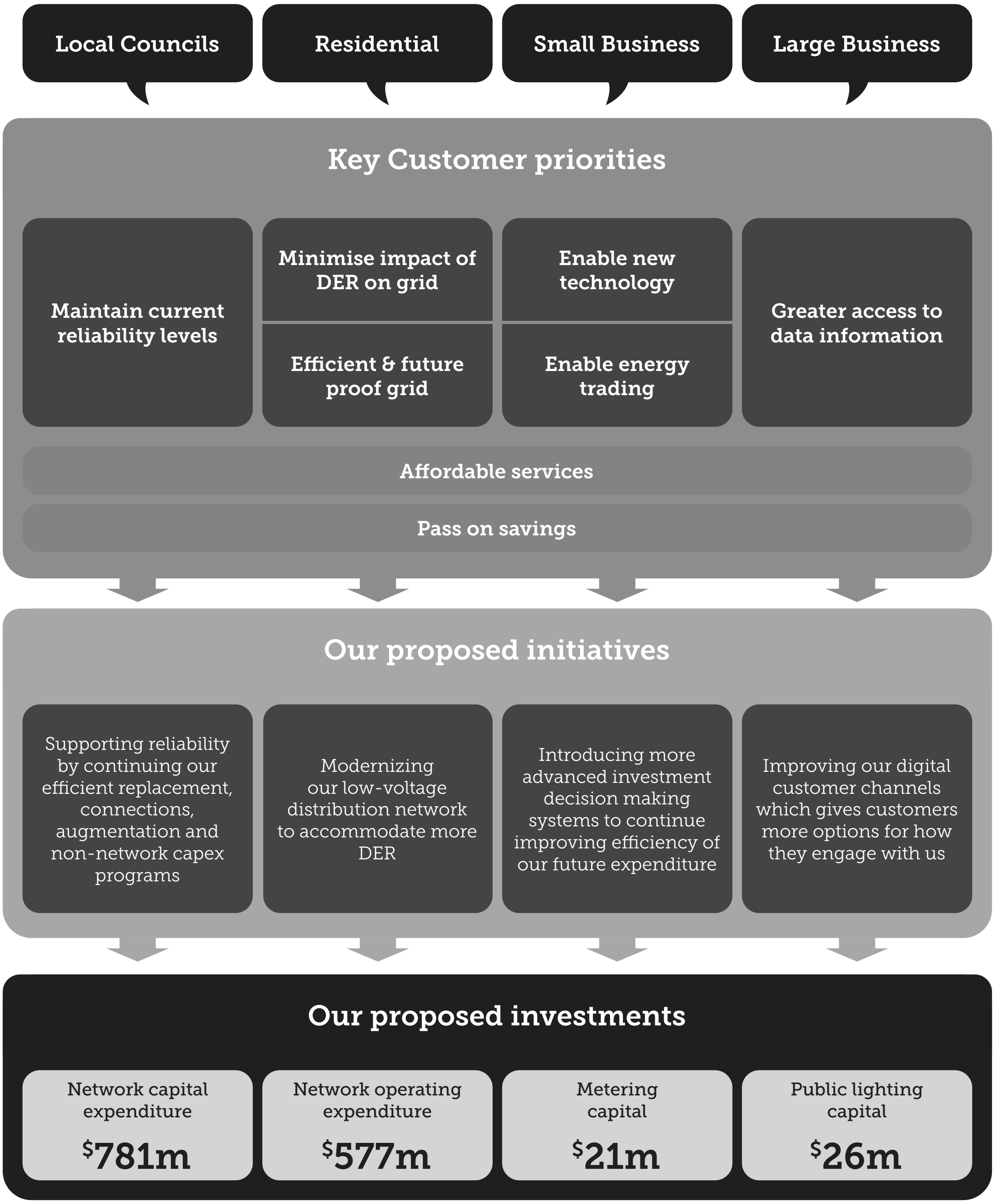
Knowing this information will allow us to invest in the right areas of the network to support the needs of our customers.

04 Investing in the network to deliver a sustainable future

Up to this point, we have outlined the impact of changes to the energy market and shown what our customers need from their network. In this section, we outline our program of initiatives for the next regulatory period, the benefits we expect to deliver, and how they relate to our customers' recommendations.

4.1 How have our customers informed our Proposal?

Figure 4.1 How our customers have informed our Proposal



4.2 The benefits we expect to deliver

As a result of the feedback from our customers, we've developed a capital and operating expenditure forecast which will allow us to deliver the following outcomes:

- Preserve the **safety** of our staff, customers and the general public
- Ensure the current level of **reliability** is retained
- Improve efficiency and place downward pressure on prices in the long term, with a view firmly on energy **affordability**
- Increase customers' ability to export excess energy that they have generated, to the grid, and prepare the electricity network to accommodate localised trading of energy in the future. This improves the **sustainability** of the network
- Provide more **choice** for customers on how they interact with and receive information from us.

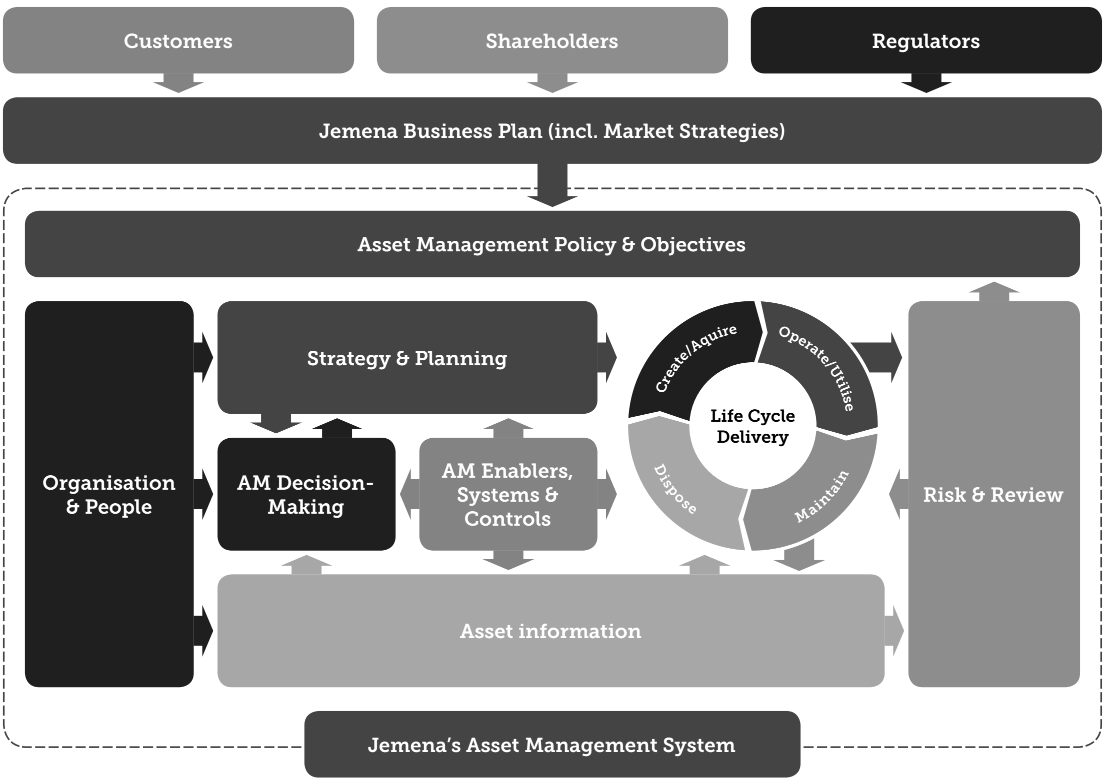
4.3 Our asset management system

Asset Management is the coordinated activity we undertake to optimise value from our electricity network. It involves the balancing of costs, opportunities and risks against performance. An Asset Management System (AMS) enables a systematic approach to the combination of management, financial, economic, engineering, and other practices applied to physical assets to provide the required level of service in the most cost-effective manner, whilst managing future risks.

Our AMS enables us to effectively direct, coordinate and control asset management activities throughout an asset's whole life. It facilitates an optimal mixture of capital investments, operations, maintenance, resourcing, risks, performance, sustainability and good governance.

Our network management system has recently been accredited under the ISO55001 standard, being one of only a few network businesses in Australia to reach this level.

Figure 4.2 Our Asset Management System



4.4 What we have done so far

In response to customers' affordability concerns, we have an existing and extensive program underway to optimise the performance of current assets.

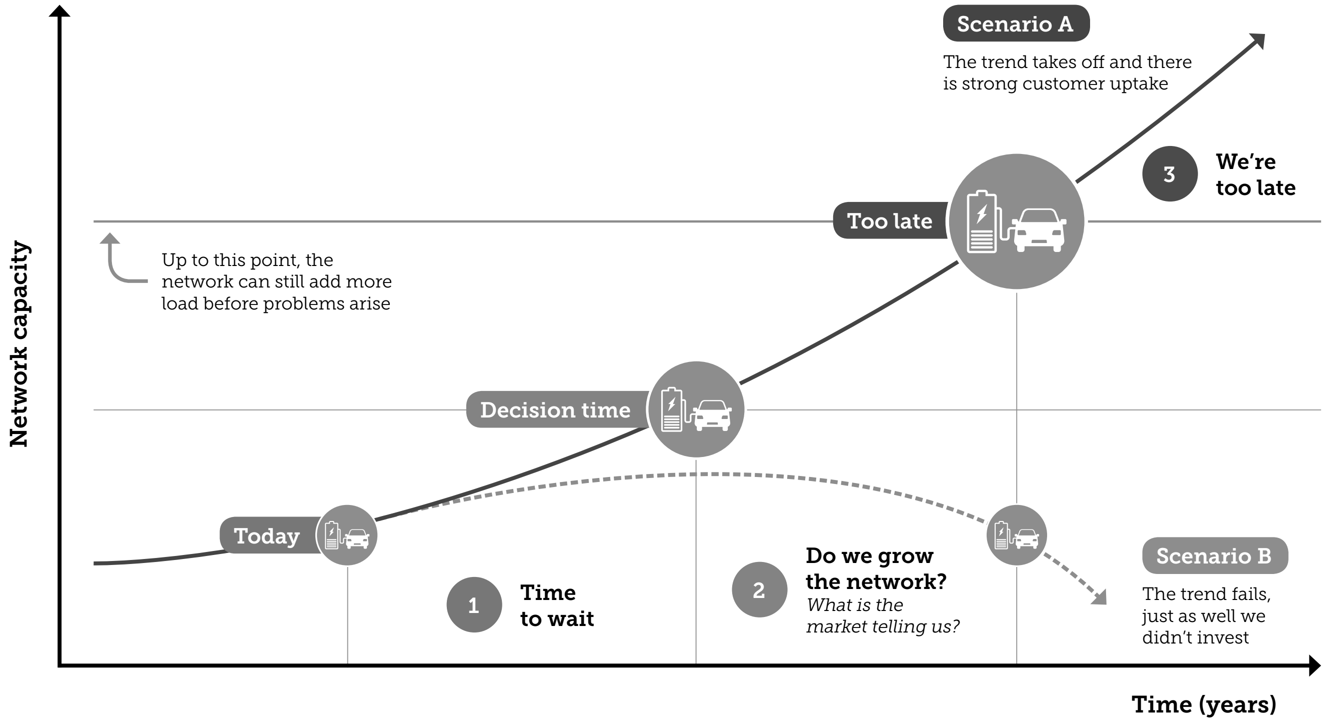
This program includes targeted measures to reduce costs and improve how our performance stacks up against other distribution networks in Australia. For example, when assessing whether a part of the network needs replacing, our first question is whether an asset of a smaller capacity will meet the needs of customers into the foreseeable future.

This means we will only invest in the network when absolutely necessary. We are also unlocking network benefits from advance metering infrastructure (AMI)—we outline these benefits in detail later in this document.

Making decisions on when to invest in the network

To meet our customers' energy expectations, we need to invest in the network to make sure electricity is available to our customers when they need it, but it can take a long time (sometimes years) from identifying a new network requirement to getting assets into service. And we need to be sure the energy needs of our customers are ongoing. We outline this challenge and how we manage it in Figure 4.3.

Figure 4.3 Deciding when to grow the network based on consumer trends



1 **Time to wait**
The trend is not yet certain, and to grow the network at this stage could be wasteful if the trend fails to materialise. Besides, the network can handle it.

2 **Do we grow the network?**
If we are going to grow the network, now is the time to make a decision because we need some lead time, the risk and costs are lowest.

3 **We're too late**
Growing the network now is costly. Having missed the materialising trend, we may even impact network reliability

In light of the level of uncertainty in the energy market, we are moving towards shorter-term investments, so we can remain adaptable and responsive to the needs of the market and our customers without compromising long-term requirements. Transformer monitoring is an example of how we are using technology to help us keep the grid affordable and reliable without spending to upgrade the network unnecessarily. We do not currently have the ability to monitor the flow through all of our distribution transformers, so to gain better insight into the loading profile on them, we have started aggregating the data from smart meters to calculate the load. Through monitoring the information collected by the smart meters, we can work out the load on the asset itself. Developing this kind of monitoring means that we can better manage how transformers operate.

The above approach makes the most of the data we have. Over the next regulatory period, we will be installing real-time monitoring equipment on our transformers to improve the accuracy of the information and, subsequently, the efficiency of investment.

4.5 Proposed initiatives

We believe we can improve the resilience of the grid through a number of measures, including integrating and coordinating DER as we commence our Future Grid program.

We anticipate the penetration of DER in the electricity network could increase from 10 per cent today, to 28 per cent by 2025-26 and possibly even to 40 per cent by 2035. This significant increase brings a range of technical and commercial risks.

It is important that we prepare the electricity network for this DER penetration quickly, because delaying action could translate to unnecessary network costs– we outline this cost and risk paradigm in Figure 4.3.

To meet our objectives in demand management, and to ensure we provide dynamic network solutions, we are introducing a number of projects, many of which leverage the benefits of the investments in AMI:

- Provide access for 65 MW of renewable energy generators with a platform for local energy trading.
- Provide access to connect over 50 MWh of new customer-owned battery storage to the grid.
- Streamline customer experiences when requesting services or information from us.
- Invest in new technology which will help optimise the timing of future network investments.
- Enhance the security of critical IT systems in response to an environment of heightened threat.
- Connect micro-embedded generators efficiently, to maximise the capacity of low voltage networks to receive power from decentralised sources of power generation.
- Develop dispatch algorithms that optimise load reduction among participating customers.

An operational model of the low voltage network

We want to use data from our low voltage network so that we can simulate various scenarios—like what would happen if more of our customers feed electricity into the grid at the same time, or changed their consumption dramatically—to assess the impact and work out the best way to manage the risk.

If we identify that certain areas of the network are at a high risk of failing, then it makes sense that any low voltage management strategy would have more emphasis on monitoring these areas rather than those deemed to have lower risk. A range of techniques are available to us to manage the network, from adopting hard constraint limits on usage and curtailing customers from using/feeding-in more than that amount, all the way through to taking the view that customers cannot be constrained at all. The network must, therefore, be augmented to allow customers to behave as they choose. Between these two extremes lie a whole range of approaches, all of which impact customers differently as well as influence the amount of investment required.

This work will deliver us the ability to:

- Conduct low voltage network modelling
- Conduct low voltage network monitoring
- Gather DER information
- Control (mediate) DER to manage uptake on the grid.

This initiative will bring us the ability to remotely control grid-connected assets and understand the characteristics and behaviour of ‘behind the meter’ assets. The net result will be better maintenance and management of the grid, and greater efficiency of operational and capital expenditure. This translates into lower charges to customers in the long term.

Enabling Analytics

Increased uptake of DER has the ability to provide benefits to the network, as the electricity they generate can help reduce the load on network assets during periods of peak demand. Gaining visibility over all the DER owned by customers will allow us to make the right decisions about the way we manage the network. For example, knowing which houses in a particular street generate solar power—and therefore the potential to feed into the grid—would mean we could balance the electricity loads in the street, to maintain reliability, efficiently.

Dynamic export limits

The lack of visibility we have of 'behind the meter' generation, and our inability to monitor transformers, means we currently have to impose unnecessary limits on the amount of power our customers can export to the network.

Dynamic export limits would unlock the ability to remove these blanket constraints and create frequent, automated intervals in which we can adjust the maximum amount that can be exported up and down, depending on the real-time demand.

05

We are proposing to keep our **capital expenditure** stable and maintain a **reliable network**

5.1 Our Capital Program

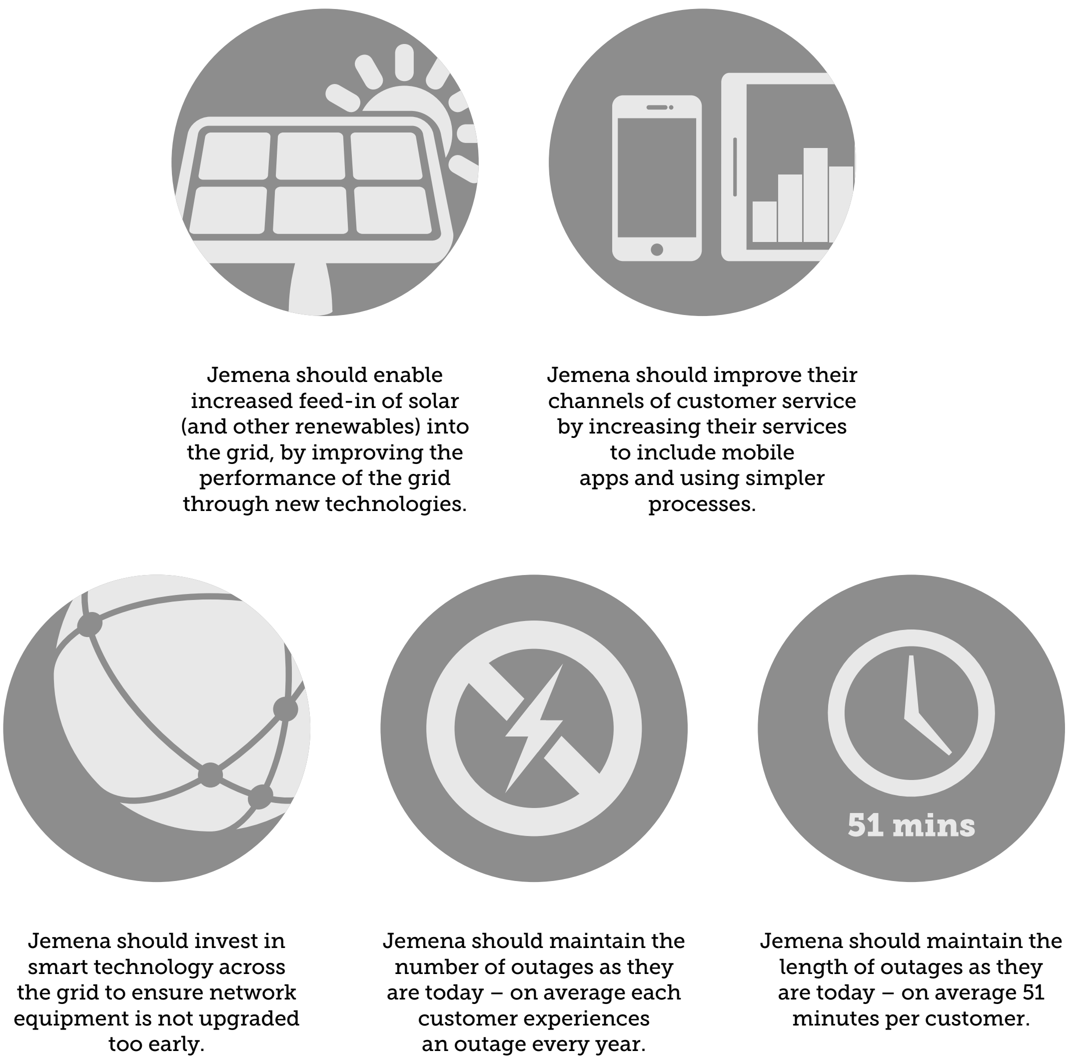
We've begun the journey to transform a network that was built to supply electricity to customers when they wanted it, to a sophisticated platform where customers are able to trade distributed energy and have power when they need it, or even have someone else do all this for them.

Facilitating this involves significant change and cost, and despite an increase in the size of our customer base growing at more than 10 per cent over the 5 years, we plan on keeping our capital expenditure for the next regulatory period in line with the $778 million of capital expenditure we expect to spend in the current regulatory period.

As you will see in our capital expenditure proposal, about a third of our spending is on connecting customers, a third on replacing assets and of the rest, 17 per cent is spent on IT and fleet, which leaves the remaining proportion for growing the network (augmentation) and enabling the Future Grid.

We've developed a capital expenditure forecast that will allow us to maintain the safety of our staff, customers and the general public—our highest priority—as well as implement the customer recommendations in Figure 5.1:

Figure 5.1 People's Panel recommendations for our capital expenditure



Forecasting capital expenditure is done through a ‘bottom-up’ process, in which our final figure represents the amount required to carry out the investment necessary in order to meet our customers’ desired outcomes.

During this section, we will talk about four categories of capital expenditure:

Replacement: Replacing parts of the network that have reached the end of their technical life, in order to maintain service levels.

Connections: Building or upgrading the network to connect new customers.

Augmentation: Increasing the capacity of the network to meet customer demand. We consider augmentation in two parts:

- Demand driven augmentation: more electricity is needed, so we need more network
- Non-demand driven augmentation: where the electricity network has to respond to changes in technology and regulatory or legal requirements. Increasing the amount we can import into the grid is an example of this.

Non-network: Information technology, property, fleet and other non-network assets which enable the delivery of services.

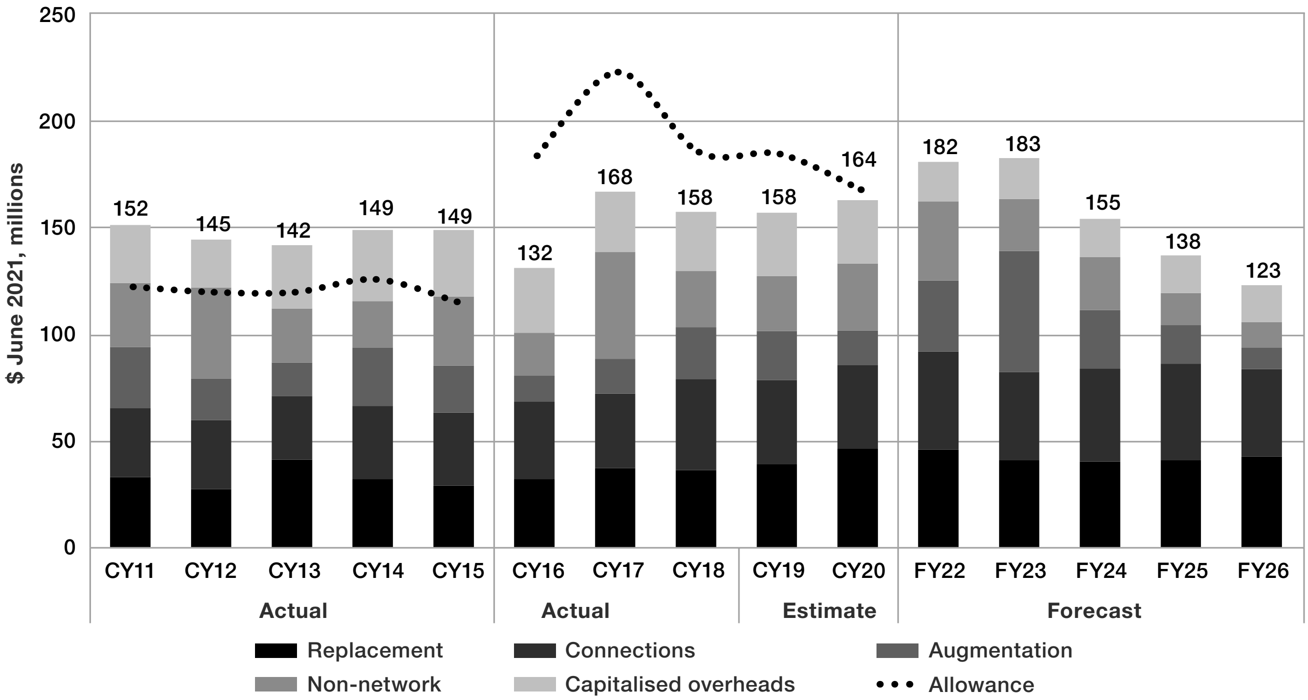
Our capital expenditure objectives

We have developed four objectives that guide our capital expenditure forecast. These objectives have been developed to reflect the outcomes our customers have told us—through our engagement program—they expect us to deliver. They also reflect our key expenditure drivers and various regulatory obligations, including the national electricity objective and the capital expenditure objectives and criteria contained in the NER. Figure 5.2 shows our capital expenditure objectives alongside the categories relevant to each objective.

Figure 5.2 Our capital expenditure objectives and how they align to capital expenditure categories

	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			✓	✓

Figure 5.3 Network services capital expenditure by category



Throughout this Regulatory Proposal we have ensured that our planned capital expenditure represents the most efficient way of meeting the objectives we have identified, as well as our regulatory obligations.

Our forecast does not include additional costs to improve network reliability, as our customers have told us they do not see the value in paying for these improvements. They did, however, tell us that we needed to maintain our current levels of service and therefore our forecast does include expenditure to ensure that the level of reliability we currently provide does not degrade.

Figure 5.4 Reliability over time–unplanned SAIDI (measures the duration of outages)

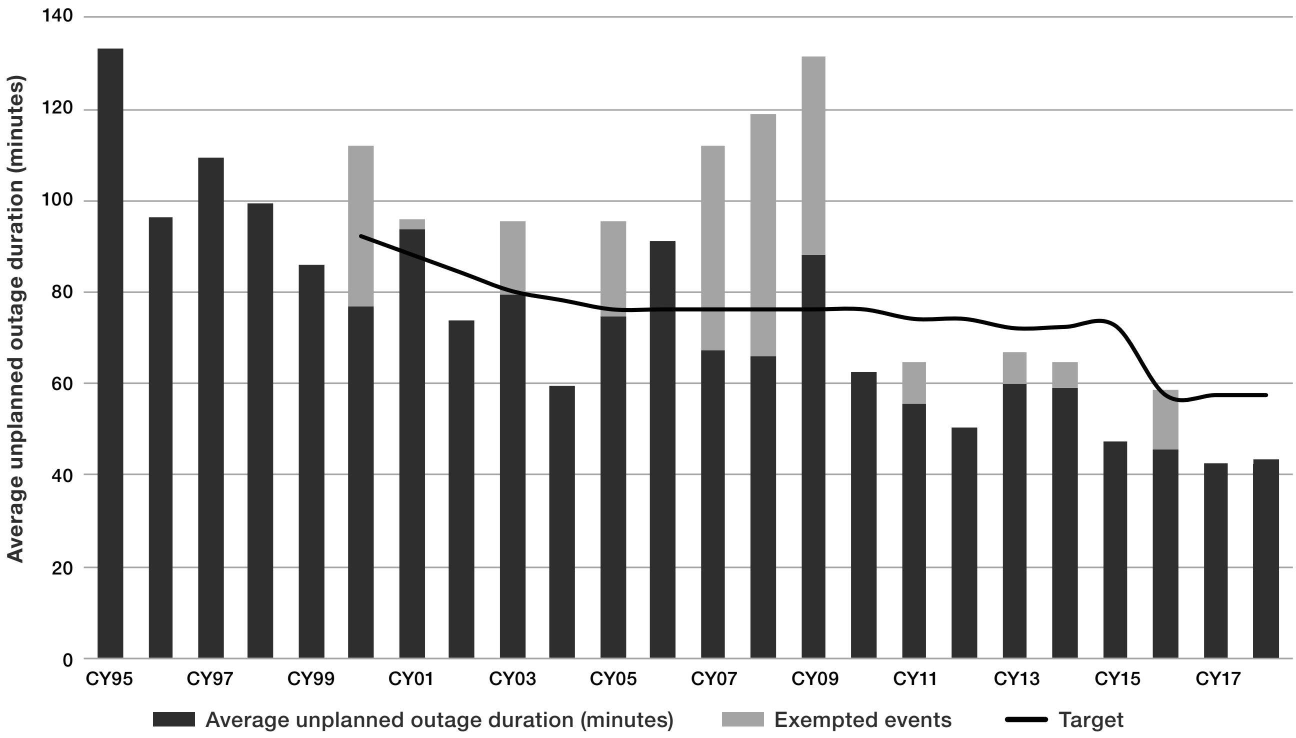
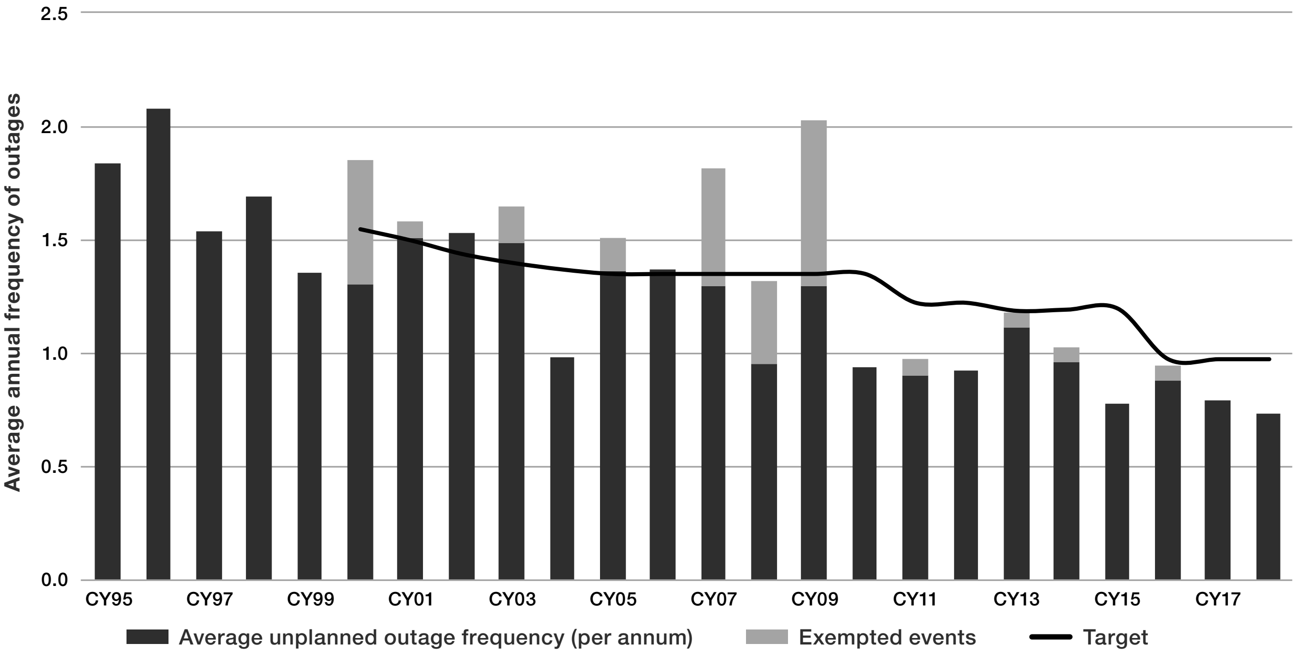


Figure 5.5 Reliability over time–unplanned SAIFI (measures the frequency of outages)



When we make investment decisions, we do so in the knowledge that our customers place a high value on reliability and affordability. We will therefore seek out smarter and more innovative ways to replace ageing parts of the network, though we will not compromise on safety.

Our core services associated with the distribution of electricity on the shared network are called Standard Control Services (Network Services). For the next regulatory period, we forecast capital expenditure of $781 million, which includes $91 million of network overheads. This compares to $799 million in the current regulatory period.

For our new customers, we charge for connecting to the shared network through a capital contribution charge; we subtract this from our total capital program. For the next regulatory period, we estimate capital contributions will be $117 million, up from $90 million in the current regulatory period. With more of the capital being paid for by new customers, we can keep our prices lower.

To develop this forecast, we have:

- ensured our planned replacement volumes are based on the best available information we have about the actual condition and health of the network, so that we only replace—or remediate—assets when necessary to maintain service levels.
- developed maximum demand and customer number forecasts and continued to use a pragmatic approach to augmentation and replacement expenditure.
- explored the ways in which we use capital and operating expenditure together, to see whether one can be substituted for the other.
- considered future levels of customer demand and explored opportunities to step down asset sizing where appropriate, rather than spend unnecessary funds on like-for-like replacements.
- ensured that optimal investment decisions which minimise the total lifecycle cost of achieving our objectives and providing services to customers are made.
- ensured all the costs that make up our capital expenditure forecast are efficient.

5.2 Replacement

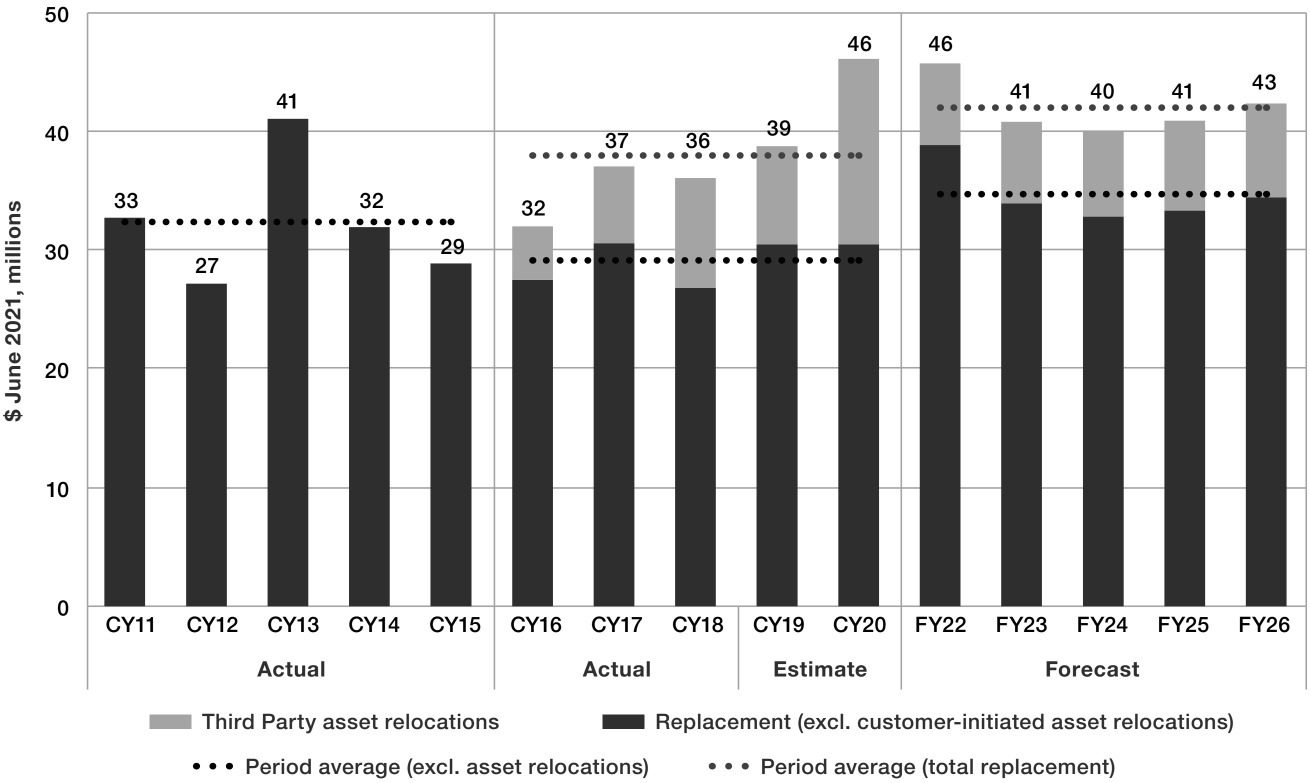
The technical failure at the end of an asset's useful life is the kind of problem that every asset-intensive business has to face.

When it comes to replacing our assets, our objective is to meet customers' expectations that we maintain current levels of network reliability over the long term, at the most efficient cost.

Our forecast for the next regulatory period comprises $211 million of direct replacement capital expenditure. This represents a 6 per cent increase compared to the current regulatory period.

As customer-initiated asset relocation works are largely funded by customers requesting the works, the more relevant replacement capital expenditure is $174 million of direct costs, which represent only a 5 per cent increase relative to the current regulatory period. We believe it represents the most efficient way of using our capital to achieve our objective around reliability.

Figure 5.6 Replacement capital expenditure



How customers have informed our replacement capital plans

Our customers gave us the following recommendations that are relevant to our replacement expenditure program:

Figure 5.7 Customer recommendations driving replacement expenditure

Jemena should improve their channels of customer service by increasing their services to include mobile apps and using simpler processes.

Jemena should maintain the number of outages as they are today – on average each customer experiences an outage every year.

Jemena should maintain the length of outages as they are today – on average 51 minutes per customer.

Our replacement capital expenditure forecast takes into account assets reaching the end of their technical lives and being unable to continue performing as required. This includes:

- some network assets which are reaching the end of their life and whose condition indicates they are at heightened risk of failure.
- the continued need to replace some families of assets which present known safety or supply risks, such as some pole top structures in high bushfire risk areas.

In light of our customers' views and in keeping with our legal and regulatory commitments, we have developed the following replacement plan:

- The continuation of our long-term program to replace some large families of assets—including poles, cross arms and overhead services—whose condition continues to degrade. Our focus is on assets that pose the highest risk to safety and to our ability to maintain current levels of service—should they fail.
- We will implement new technologies that will allow us to defer capital expenditure on larger network assets in the future, for example, zone-substation transformers. However, we anticipate consistent levels of capital expenditure on smaller assets—where their performance is expected to degrade during the next regulatory period and their failure could have serious consequences for safety and reliability.
- Following on from a significant replacement program during the current regulatory period, there will be a reduction in the amount of zone substation equipment we will need to replace. However, there is still a need to replace transformers, switchgear and other equipment at some zone substations that were originally installed in the 1960s, as this equipment poses a high risk of being unable to maintain supply to customers in areas such as Coburg North, Coburg South and Broadmeadows.
- Continued strong demand from customers and other authorities for the relocation or rearrangement of network assets to facilitate the construction of major public infrastructure projects, like level crossing removals. The costs of these works are funded by the requestor.

5.3 Connections

We spend money to connect new customers and reinforce the network to meet new customer demand.

Since 2016, we have experienced strong growth in customer numbers. This is expected to continue during 2021-26, albeit, at a slower/lesser rate.

Our objective in the next regulatory period is to connect new customers, ensuring we can meet or manage expected demand, at an efficient cost, over the long term.

As a result, our capital expenditure forecast for the next regulatory period includes $218 million of direct costs for connections, including the portion of the connections that our customers make a financial contribution towards. This represents a 6 per cent increase in connections capital expenditure from the current regulatory period.

Our connections expenditure is driven by customers' requests, and the number generally correlates with economic activity in our network area. Over the forecast regulatory period, we believe we will continue to see strong growth in the number of new customers we need to connect, including:

- 30,000 new residential dwellings
- 1,300 new small to medium businesses
- 3 new very large businesses.

Overall, our forecast for routine connections expenditure is in line with growth trends and expenditure seen during the current regulatory period. Given the highly specific and customer-driven nature of non-routine connections projects, the trends for these major projects are harder to predict. As a result, our forecast in this area reflects our best-available information from our largest customers about their plans and requirements of us, and includes several major commercial, residential-development and infrastructure projects.

Figure 5.8 Historic and forecast customer numbers

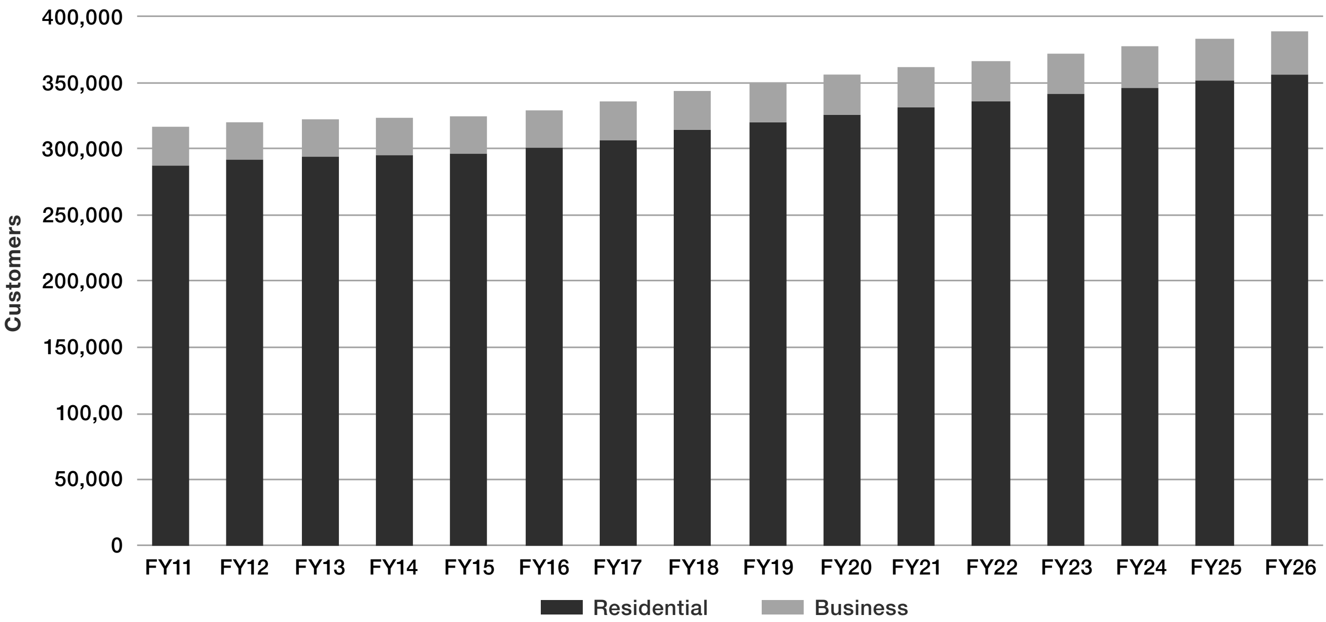
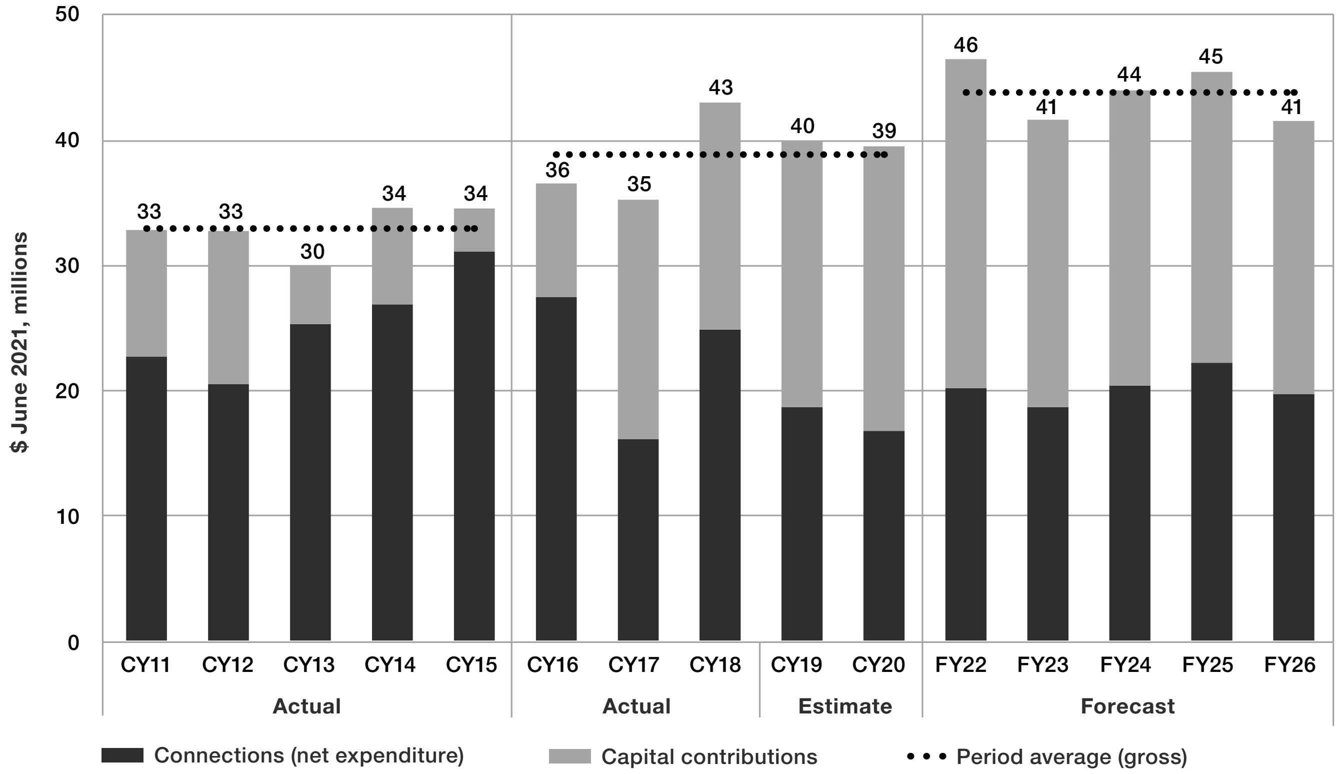


Figure 5.9 Connections capital expenditure



5.4 Augmentation

From time to time, we need to build new parts of our distribution network to meet overall growth in the demand for electricity or respond to technology advancements, or regulatory and legal requirements.

Growth related augmentation is not attributable to any single customer but is triggered by a general uplift in the use of electricity by all customers, this includes:

- a group of customers whose load generally rises over time—for example, households continue to add more appliances and devices
- customers highly likely to connect to the established electricity network—for example, new developments on the outskirts of our network area
- customers who modify their connections, including those in areas where residential density is increasing—for example many single-storey houses in Coburg are being converted to multistorey townhouses. This is in an area that has a greater need than can be met through the existing network capacity.

Some large infrastructure projects can trigger augmentation plans to ready an area of the network for large new loads. Although those loads are not reserved solely for these customers—all of the existing and potential customers in those areas can enjoy the increased capacity. Some projects that have already been publicised include:

- North East Link tunnel construction supply
- Major data centre supplies
- Melbourne Airport expansion.

More recently, we have seen new trends emerging that drive augmentation expenditure. There has been growing demand from residential and small business customers who are more actively involved in the way they manage their energy usage. This has been driven by:

- Victorian renewable energy targets that will encourage new embedded generators, batteries and electric vehicles to connect
- Strong customer interest in using the grid to export and trade the clean energy they have generated using DER.

To determine the required growth related augmentation capital we take these factors—amongst others such as regional development plans, population plans—into consideration to forecast system maximum demand.

Forecasting Maximum Demand

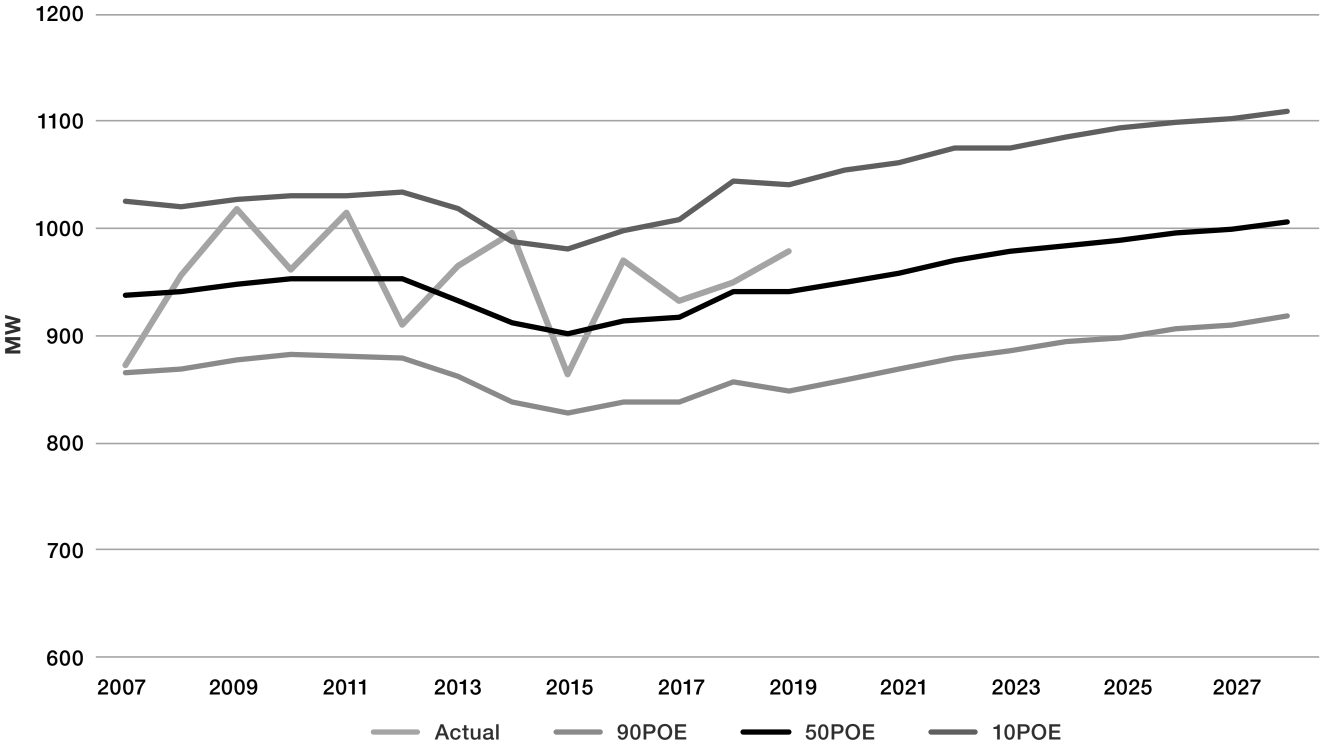
Maximum demand is a key driver in determining the amount of revenue we require in each regulatory period to make sure the electricity is always there when needed. As a consequence, making the right assumptions in our modelling is imperative. If we underestimate, we put the reliability of the network at risk. Conversely if we overestimate, it means our customers pay more for improvements to the network than are strictly necessary, we note this in Figure 4.3.

To make sure our demand forecast covering the next regulatory period is as accurate as possible, we undertook comprehensive analysis to forecast trends—including incorporating the views and experience of an external agency to conduct the research and present an independent view of likely forecasts. See Figure 5.10 for our system maximum demand forecast.

The forecast shows continued growth of maximum demand, largely driven by the changing composition of our customer base from heavy industrial, towards commercial and residential customers who are less energy-intensive users. In the absence of other changes, this means we will spend less money augmenting—growing the capacity of the electricity network—than we would have, say, ten years ago.

We focus on maximum demand over the summer season, because this is the time of year it is at its highest and the electricity network is under the greatest pressure. Summer maximum demand is expected to grow at 0.7% per annum over the ten years commencing from summer 2018-19.

Figure 5.10 System maximum demand

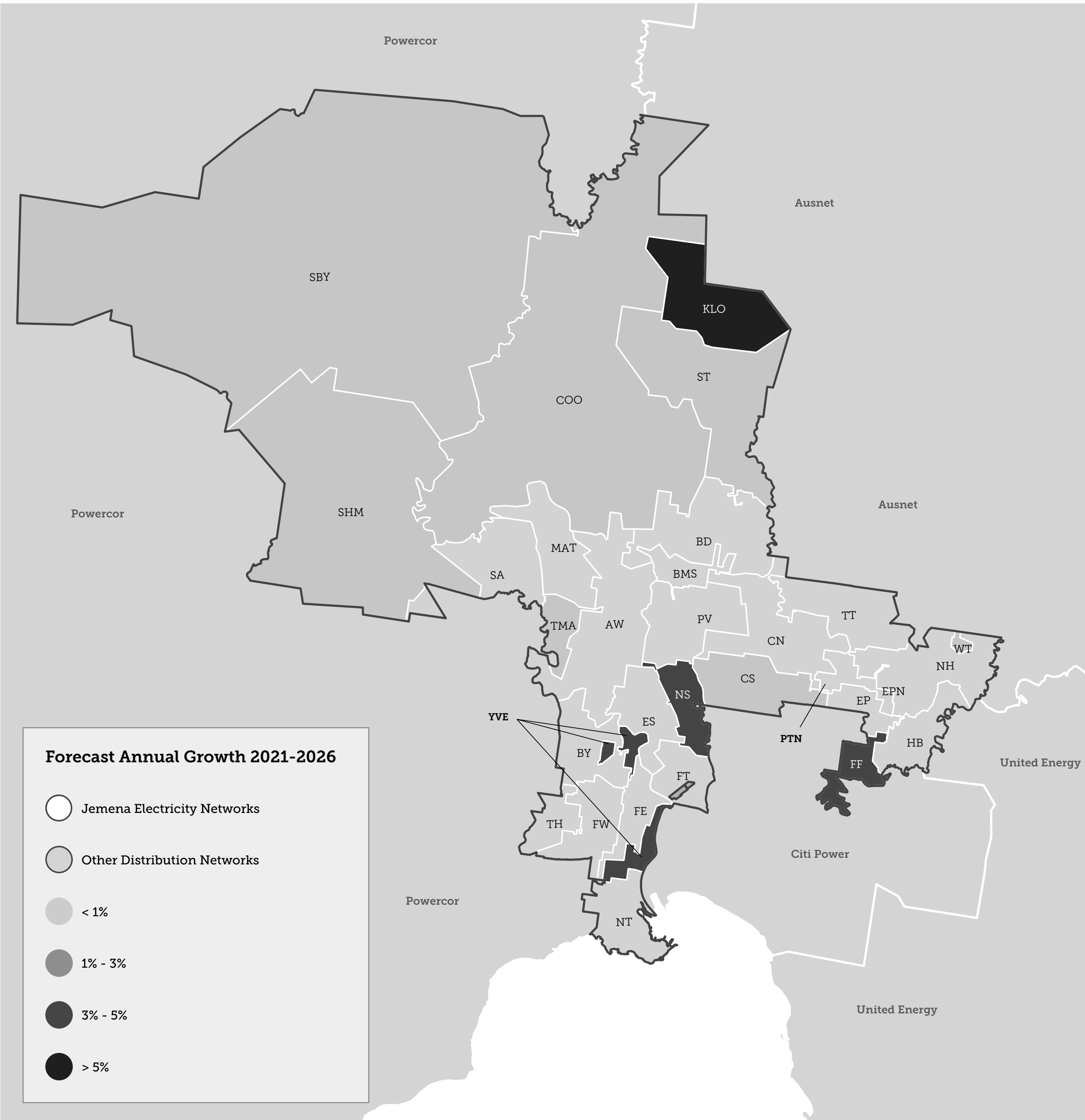


Of course, our peak demand forecasts are not uniform across the electricity network and we need to adjust our capital expenditure forecast to accommodate these variances in the local areas. In Figure 5.11, we show that development in areas like Craigieburn, Tullamarine and Fairfield is expected to drive higher growth in demand.

What is POE?

When considering the future demand for electricity, we develop multiple forecasts with different levels of 'probability of exceedance' to account for the potential variability in actual demand. A 10 per cent probability of exceedance forecast has a 10 per cent chance that the actual demand will be higher than the forecast, and a 90 per cent chance that actual demand will be lower than the forecast.

Figure 5.11 Growth diversity across the electricity network



How customers have informed our augmentation plans

Our customers have said that they expect us to run an efficient, future-proof network, and want us to play a key enabling role for deploying new technologies and products that have emerged with the growth of DER.

Figure 5.12 Customer recommendations driving augmentation expenditure

Jemena should enable increased feed in of solar (and other renewables) into the grid, by improving the performance of the grid through new technologies.

Jemena should maintain the number of outages as they are today – on average each customer experiences an outage every year.

Jemena should maintain the length of outages as they are today – on average 51 minutes per customer.

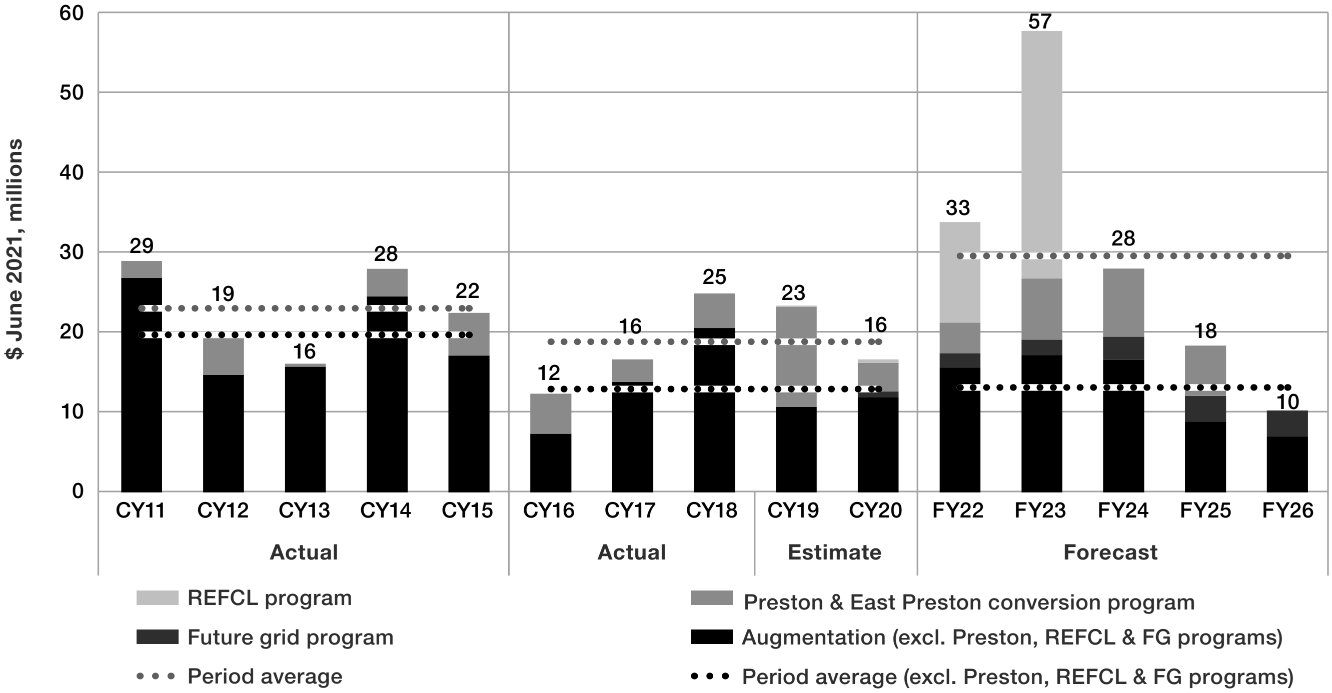
As a result, we developed our augmentation expenditure forecast to meet the following objectives:

- 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.
- Minimise any constraints on electricity exports from DER to the grid, and do so as efficiently as possible.

Our forecast augmentation expenditure to deliver these benefits to our customers over the next regulatory period is $147 million. This represents a 55 per cent increase on what we spent augmenting the network in the current regulatory period.

After excluding once-off items (namely the future grid and REFCL programs), we are able to reduce our augmentation capital over multiple regulatory periods, some through lower growth driven by customers but also by using interval metering data for developing insights into managing the network, as can be observed in Figure 5.13.

Figure 5.13 Augmentation capital expenditure



The forecast presented in Figure 5.13 represents what we believe to be the most efficient way to deliver against the objectives noted above. Key elements of our forecast include:

- An aggregate decrease in growth related augmentation expenditure:
  - during the current regulatory period, we have focused on investing to address the risks to capacity associated with a number of our sub-transmission assets and zone substations.
  - over the next regulatory period, we forecast maximum demand growth across the network to slow, although some localised areas will continue to experience strong growth. We hope that increasing the number of customers assigned to more cost-reflective prices—prices that are representative of the cost of supplying electricity—over the next regulatory period will help this. However, the impacts can be quite delayed and therefore we do not expect this to make a material difference until the 2026-31 regulatory period.
- A significant increase in augmentation that is required because of factors other than increases in maximum demand, including:
  - expenditure on systems to improve planning and real-time monitoring and the accommodation of two-way power flows as part of our Future Grid program. These measures represent the most efficient way to enhance the network's ability to host DER exports and accommodate increased local energy trading in the future, and therefore mitigates against investing in augmentation capacity.
  - the augmentation of distribution substations to address issues with the quality of supply that has been caused by high levels of DER penetration, as well as to ensure we can maintain compliance with regulatory obligations.
  - environmental, safety and legal compliance, including the installation of Rapid Earth Fault Current Limiter (REFCL) technology at the Coolaroo zone substations during the forecast regulatory period. Our investment of $52 million in REFCL during FY22 and FY23 is the cause of the large spike in Figure 5.13.

> REFCL technology works by cancelling the energy within milliseconds of detecting a fault, which reduces the risk of bushfire. The installation follows a test by the Victorian Government.

5.5 Non-network

Information Technology and Communications

IT and Communications account for 12 per cent of our capital expenditure forecast.

IT and communications assets play a critical role in supporting the expedient and efficient delivery of services to customers, by providing the platforms to support a wide range of activities like:

- real-time monitoring and control of the electricity network and its equipment, to maintain asset health, ensure outage frequency and length are maintained and reduce long-term asset expenditure.
- interactions with customers and other market participants, allowing inquiries to be addressed more quickly.
- planning and management of field operations, including for construction, maintenance and outage response to operating as efficiently as possible.
- recording, reporting and analysis of asset and geospatial information, including for asset-management planning to respond to network issues and customer enquiries quickly.
- corporate support activities, including finance, reporting, human resources and procurement.
- new compliance obligations—including the move to five-minute and global settlement in the National Electricity Market—require us to make a number of IT system changes.

To deliver efficient outcomes for customers, we maximise the longevity of all IT assets to ensure the lifecycle of any technology—including the replacement period—takes into account the optimum time for upgrade or replacement.

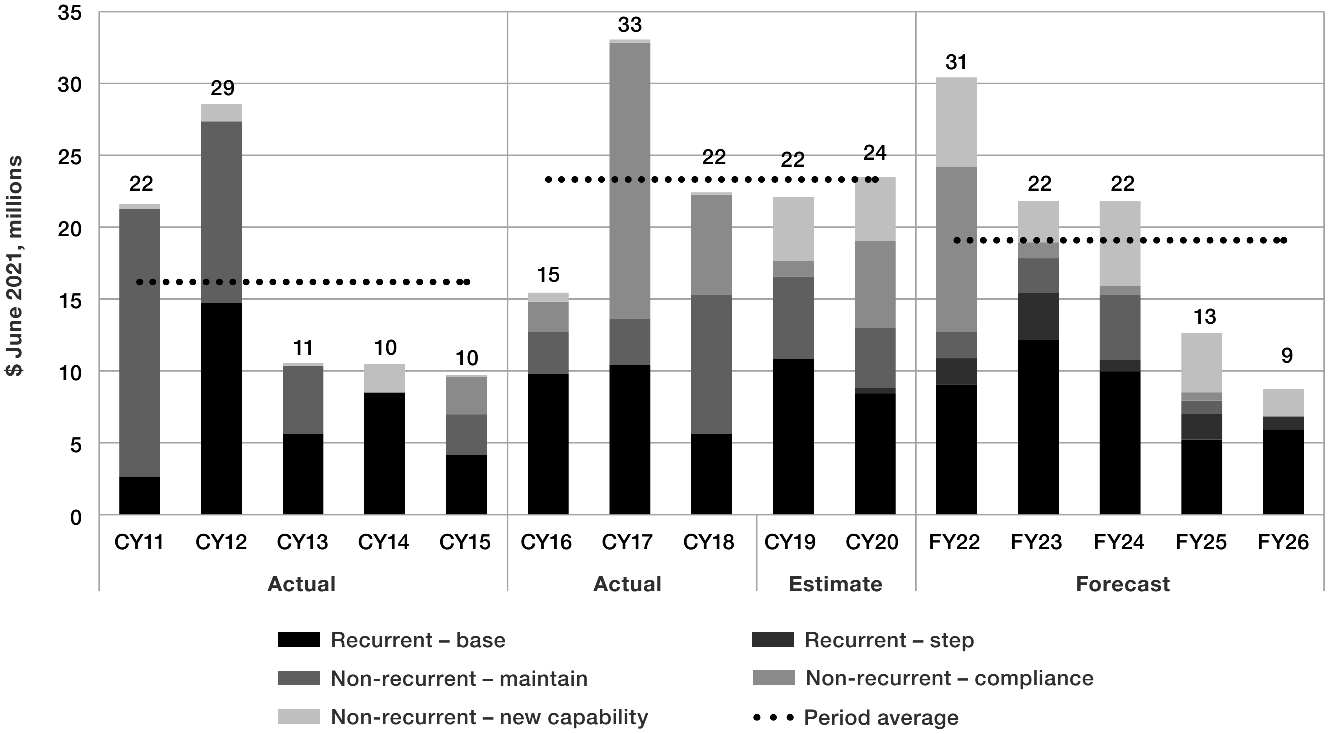
The most common reasons for replacing an IT asset includes when:

- it is more economic to replace an asset than keep it, often because the technology vendor no longer supports the product because it is too old, and the number of support resources required to maintain it are no longer viable; and where keeping it as-is represents an unacceptable risk for the ongoing delivery of services.
- the asset can no longer expand or extend to match business growth, regulatory obligations or usage requirements.
- the asset can no longer be upgraded to support other necessary system changes—examples include operating systems, hardware and network environments.
- the security of the asset cannot be maintained, and it presents a potential entry point vulnerability or exposure to a security breach.

Our Regulatory Proposal for the next regulatory period builds on the strong and stable foundations of the IT platform we developed between 2011 and 2018, a period in which we focused on building and rationalising IT systems to develop a flexible platform that allows:

- for quicker modification to meet smaller business changes and emerging regulatory obligations that are increasingly arising
- us to leverage benefits of scale to reduce future costs and manage risks
- us to propose lower IT expenditure—largely a fixed cost in the next regulatory period.

Figure 5.14 Non-network IT capital expenditure – excludes metering related costs



As can be observed in Figure 5.14, our average IT capital expenditure across three regulatory periods is stable–after excluding major compliance projects– and the balance of recurrent and non-current has changed over time following the completion of major system upgrades, and the shift towards cloud-based technologies.

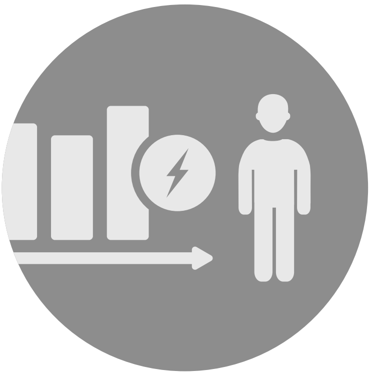
Our forecast includes expenditure in response to our customers' recommendations and to ensure we can keep delivering services in the next regulatory period efficiently:

- Continuing to replace IT assets where necessary, focusing on leveraging scale to minimise the lifecycle cost of those assets.
- Continue to meet the growing operating and data storage requirements of the business.
- Comply with new regulatory obligations. An example of this is the five-minute settlement obligation, which requires a significant investment in IT systems. This can be seen in Figure 5.14 during FY22 and FY23 where we will incur a large cost.
- Improve our online and mobile services and channels, and customer outage communications, in response to customer feedback.
- Strengthen our focus on cybersecurity and resilience, including the continued protection of privacy and data integrity.
- Commence the migration of our enterprise resource planning (ERP) system—following the declared end of support—that will span multiple regulatory periods. Planning for this will include looking at different software suites, cross-business (scale) efficiencies and other optimisation opportunities to determine the most efficient outcome at the time.

Taking all these requirements into account, we anticipate our IT capital expenditure in the next regulatory period to be $96 million of direct costs, down 18 per cent on the current regulatory period.

Five of the recommendations from our People's Panel have influenced our proposal for non-network expenditure.

Figure 5.15 Customer recommendations driving non-network expenditure



Jemena should improve the information available to customers and the ease of access to smart meter data. This should be through:
a. improving Jemena's portal
b. adding additional services such as apps for smart phones.

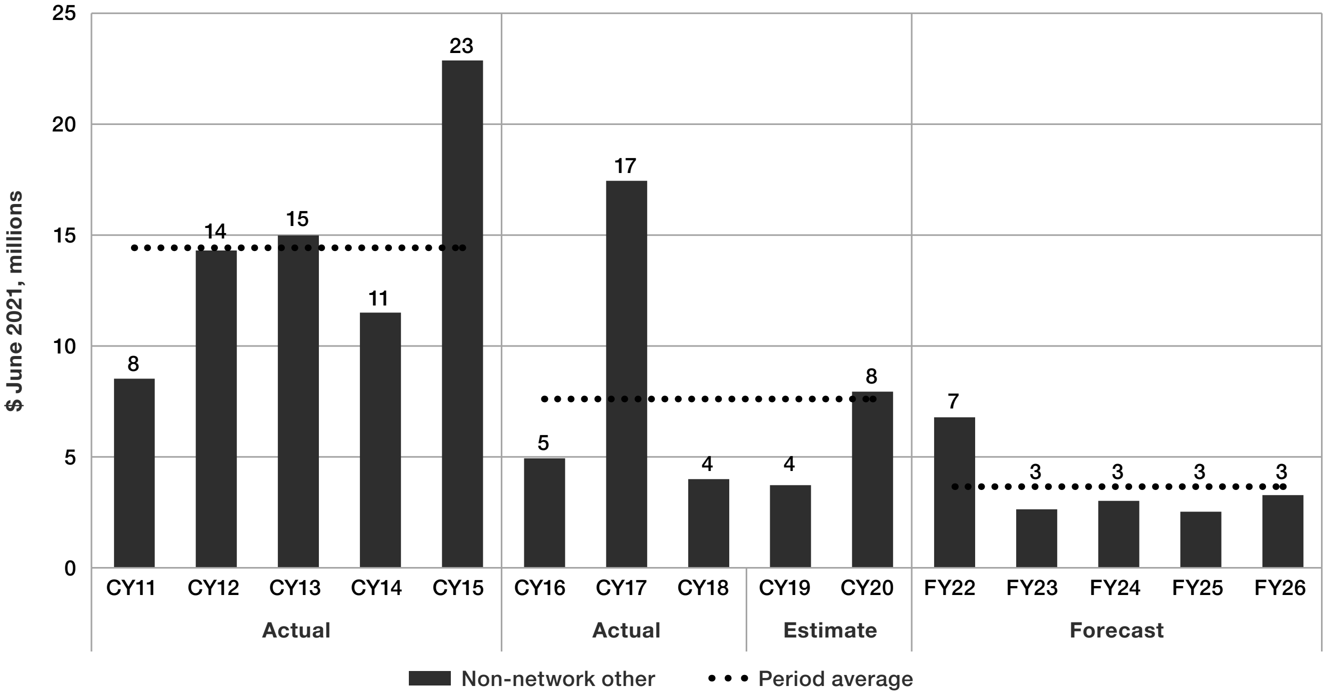
Jemena should investigate how customers could be provided with personal usage and bill information for different pricing structures.

Jemena should improve their channels of customer service by increasing their services to include mobile apps and using simpler processes.

Jemena should send SMS messages to all customers for unplanned outages. The message should include an estimation of how long it will take to fix the outage

Jemena should provide email or letter notifications about all planned outages. This should include accurate details of how long the outage will be and suggestions for how to manage the time without electricity.

Figure 5.16 Non-network other capital expenditure – excludes metering



Other Capital Expenditure

In addition to IT, our non-network capital forecast includes expenditure on other items such as vehicles and property. Over the previous and current regulatory period we have experienced some volatility in capital expenditure of this kind. This has arisen due to the deferral of some vehicle purchases and non-recurring expenditure on offices and depots. Despite this, our other capital expenditure is relatively stable from one regulatory period to another.

In the next regularly period we anticipate $18 million of direct capital expenditure and the volatility in this category to settle from year-to-year.

Property

We expect spending on property in the next regulatory period will be minimal. Only refurbishments will take place.

Fleet

The vehicles in our fleet allow personnel, specialised tools and equipment to travel around our electricity network and perform emergency fault response, repair, maintenance, inspection and construction. Our fleet is therefore critical to us delivering the services required to maintain a reliable network.

As with our network assets, the condition of vehicles deteriorates with usage and time, and this reduces their functionality and performance, increases ongoing operating costs and, in some cases, creates safety risks to the community and the people operating them.

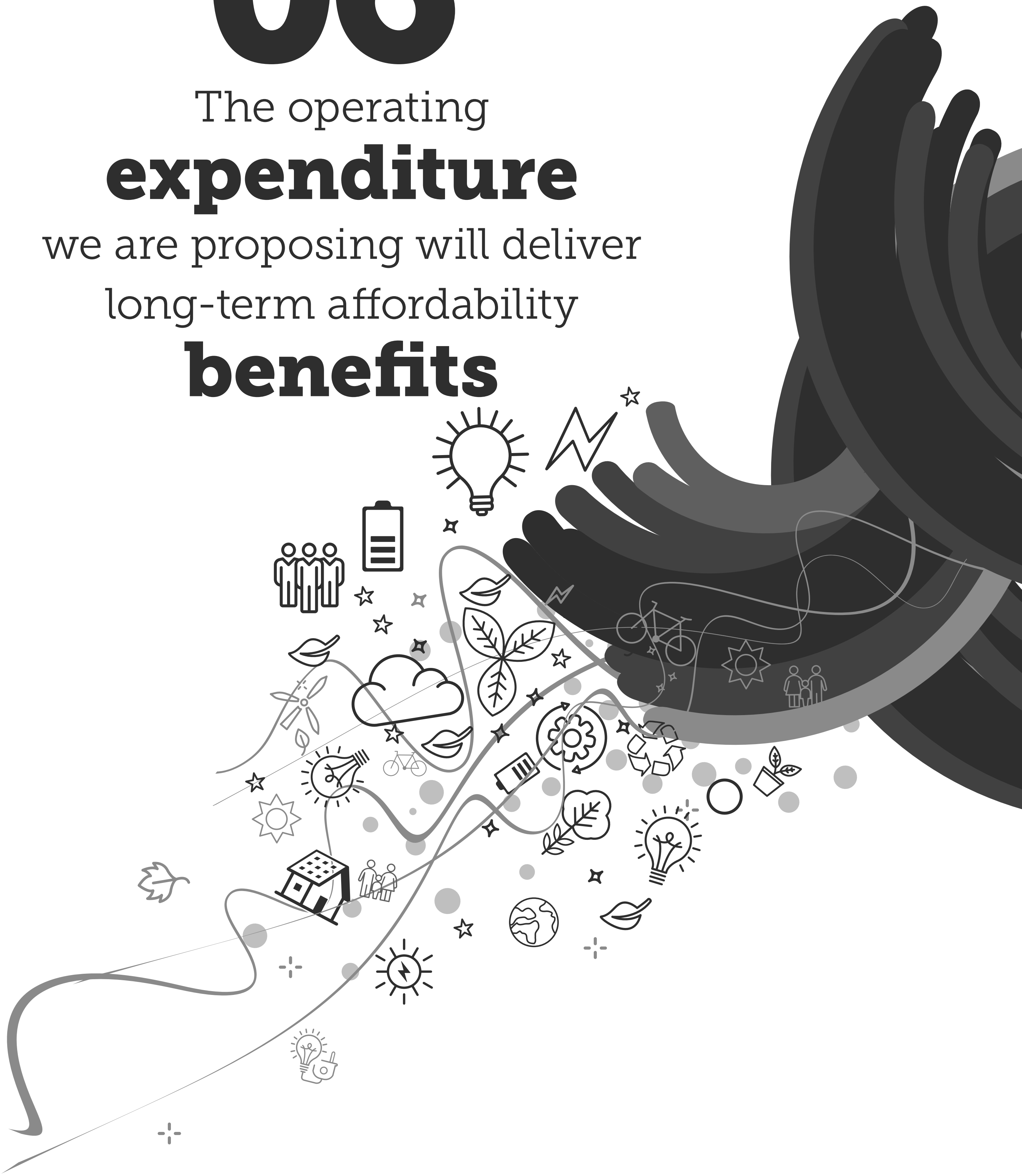
Our forecast, therefore, includes expenditure to continue our replacement program and funding to rebuild some types of elevated work platforms and heavy commercial vehicles to extend their lives, where it is economic to do so. The actual condition is the primary factor we use when determining whether a vehicle requires replacement.

5.6 Further information on our capital expenditure program

More information on our capital expenditure program can be found in Attachments 05-01 to 05-11.

06

The operating **expenditure** we are proposing will deliver long-term affordability **benefits**



Our operating expenditure for Network Services includes the costs of operating and maintaining our physical assets—for example, poles, wires and computer systems—responding to emergencies like trees that have fallen on our electricity lines, and performing customer functions like responding to enquiries and providing billing information to retailers.

In preparing our forecast, we must demonstrate that our proposed spend is efficient before the AER will accept it.

To maintain reliability we need staff and equipment to respond to faults and emergencies. Those frontline workers need to be supported and coordinated through operational activities. We need to continue supporting the strategic development of the network and to report our compliance with economic and safety regulations. We must also provide good customer service, by having our call centre staffed to provide timely responses to customer queries, and to allow us to engage with community programs, such as those sponsored by Kildonan, to help customers manage their energy needs.

In developing our Proposal, we have forecast our operating expenditure using the AER's preferred forecast method, 'base, step, trend'. The method forecasts future operating expenditure using a 'base' year – where the operating costs are representative of the efficient costs necessary to operate and maintain the network, and meet regulatory obligations.

We have also used specific forecasts for items that the base year operating expenditure does not provide a reasonable basis with which to forecast future expenditure requirements.

We are using our lowest opex year 2018 as the base year for forecasting our operating expenditure. This is because our 2019 opex contains costs associated with running a transformation program that we do no expect to incur in the next period. This helps in lowering our forecast operating expenditure.

This reduction in forecast operating expenditure helps to reduce the network component of a customer's bill, and is one of the ways in which we are contributing to making electricity more affordable. Our customers are particularly concerned about the rising costs of living and are especially keen to see some stability in the price of essential services like electricity. In turn, this helps them to plan and manage household and business budgets and their energy costs. This is something our customer engagement sessions indicated was a high priority.

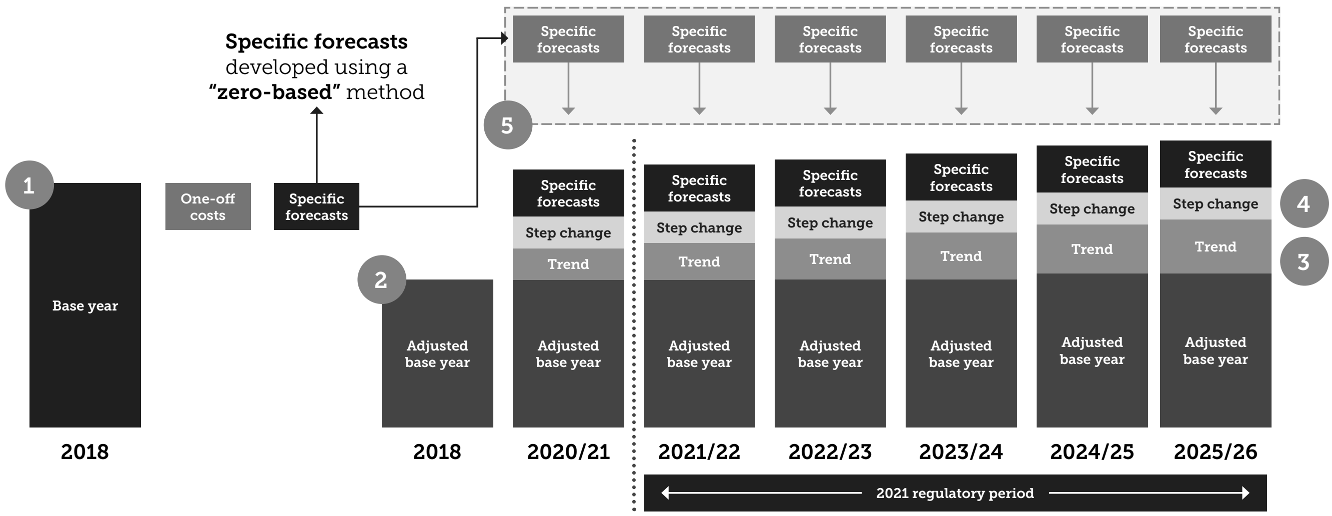
To comply with the NER and to assist the AER in assessing our forecast operating expenditure, we have assigned our costs to four categories, and allocated these to the relevant services using our approved cost allocation methodology. The categories are:

- **Network maintenance**—expenditure associated with conducting routine, non-routine and vegetation maintenance of, and around, the electricity network, and responding to emergencies—such as outages caused by storms—to ensure we can meet our safety and service obligations and provide the level of service our customers expect.
- **Network operating**—expenditure associated with managing the design, planning and operation of the network, and providing training, safety and corporate support.
- **Non-network**—expenditure associated with the operation, maintenance and leasing costs of our IT systems, vehicles and property.
- **Other**—expenditure including levies and land taxes, insurance costs to manage specific risks, and the debt-raising costs required to finance our capital program.

6.1 Forecasting operating expenditure

We adopt the AER's preferred approach to forecasting Network Services operating expenditure by using the base-step-trend methodology.

Figure 6.1 AER's preferred operating expenditure forecasting methodology



Our five-step opex forecasting approach

1. **Step 1:** Establish the efficient base year
2. **Step 2:** Adjust the base year for non-recurrent expenditure
3. **Step 3:** Trend the base year forward
4. **Step 4:** Adjust the trended base year for step changes
5. **Step 5:** Add specific forecasts

Total operating expenditure, excluding the effects of inflation, is forecast to grow at an average annual rate of 1.40 per cent per annum relative to the base year. This reflects the combined impact of:

- A forecast 1.05 per cent growth in wages per annum—where internal labour costs are benchmarked to account for around 60 per cent of operating costs;
- A forecast 1.28 per cent increase in output growth to ensure greater funding for servicing our network as it grows over time; and
- A 0.5 per cent reduction attributed to productivity; this is consistent with the AER's recent review of productivity for electricity distribution businesses.

6.2 Benchmarking

Every year, the AER benchmarks the performance of the distributors against each other. They analyse data provided by the electricity distribution businesses and run it through various models to take a view on which distributors are efficient and which, in their judgement, are not.

The AER employs a number of techniques to undertake its benchmarking analysis, for most methods we rank well amongst our peers, particularly those that look at a network business as a whole. These econometric methods include multilateral total factor productivity and partial indicators. Our total cost and capital expenditure productivity is generally amongst the most efficient businesses; however, on operating expenditure alone, we do not benchmark amongst the most efficient. When considered in the context of overall costs and operations, we are an efficient electricity distribution business.

For the current regulatory period, we are incurring less operating expenditure year-on-year than the efficient allowance the AER considered was reasonable in their decision.

Nevertheless, we have implemented a transformation program to deliver an immediate reduction in operating expenditure in the latter years of the current regulatory period, which delivers ongoing reductions over the next regulatory period.

6.3 Setting the efficient base year

For the purposes of forecasting, we consider the third year of the current regulatory period—2018—as the efficient year on which we have based our operating expenditure forecast for the next regulatory period.

We consider our base-year expenditure will be efficient for the following reasons:

- We are subject to a regulatory incentive framework for both operating and capital expenditure and have responded to these incentives.
- Benchmarking analysis generally supports the efficiency of our operations.
- We have performed well by keeping our operating expenditure below the AER's allowance—which is set at a level that is considered efficient—in the current regulatory period.

Through our transformation program, we sought to find new ways of delivering the same levels of service at a lower cost. We are rearranging our field staff to maximise savings by leveraging scale, implementing streamlined processes and systems to reduce manual process handling, and introducing other resource-saving initiatives. We are working to have this program completed in 2019 and just before the commencement of the next regulatory period.

We are committed to the reductions, so much so, that we are passing on these benefits to our customers in this Proposal.

6.4 Treatment of corporate overheads

Up to and including the current regulatory period, we have capitalised our corporate overheads.

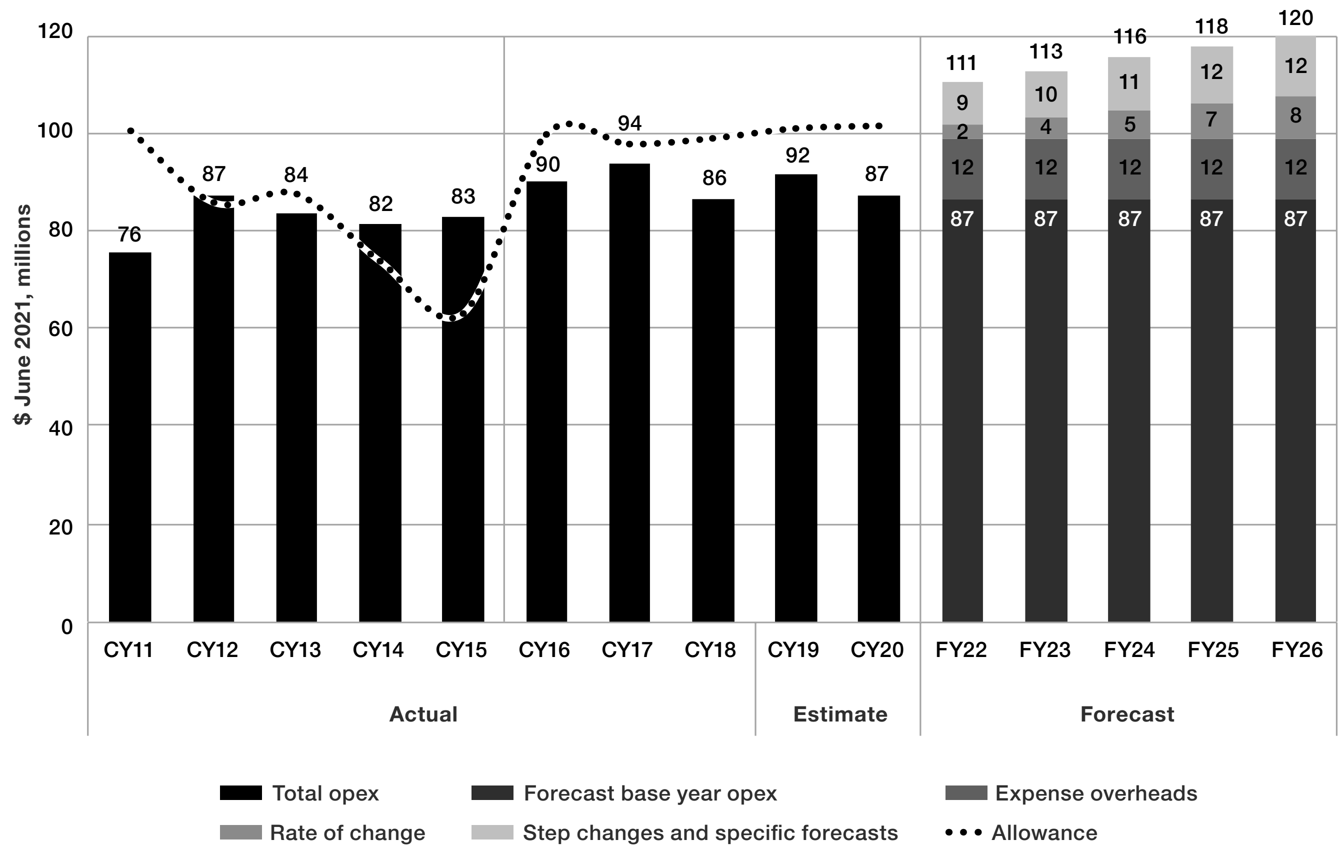
Under our previous approach, we capitalised corporate overheads and recovered the expenditure over the life of network assets–most are greater than 20 years. This approach didn't seem right for short-term costs such as corporate overheads. We have obtained approval from the AER that we will expense all corporate overheads from 1 January 2021.

The national electricity objective requires us to look out for the long-term interests of customers, and by changing our approach to corporate overheads, we believe we are doing just that. It means we reduce the long-term investment. In other words, future generations are not burdened by the cost of action we take and the expenses we incur today.

6.5 Our proposed operating costs

The graph below shows the operating expenditure forecasts for our Network Services over the next regulatory period, along with our actual, expected and allowed operating expenditure for the previous (2011 to 2015) and current (2016 to 2020) regulatory periods.

Figure 6.2 Forecast operating expenditure for the past, current and next regulatory periods



With reference to this chart, there are a number of noteworthy points:

- From 2016 onwards, some costs were reclassified from metering to Network Services, which partially explains the reason why metering costs fall and Network Services costs rise in 2016 compared to 2015. We also identified a number of substantial operating expenditure step changes in 2016 which contributed to the increase in operating expenditure regulatory allowance during the current regulatory period.
- When it made its decision for the current regulatory period, the AER set an operating expenditure allowance that is considered efficient. Each year, we have operated below this level. This means we have managed operating expenditure efficiently.
- We have undertaken a transformation program in 2019 to reduce labour expenses and introduce processes and systems for greater automation to deliver long-term savings. These are 'one-off' costs that will allow us to achieve lower operating costs in future years, despite rising costs and supporting a larger and more complex network.
- The figures for expenditure in the years 2019 and 2020 are estimates and are exclusive of transformation costs. They are lower than they would have been had we not incurred these transformation costs.
- By using 2018 as base year, we are excluding transformation costs from our base expenditure for the purpose of forecasting expenditure in 2021-26. This is because transformation costs are not representative of our recurring operating expenditure.
- There is a $12 million increase in our 2021 forecast expenditure that is due to the change in the way we will treat corporate overheads. However, this is offset by a reduction in capital expenditure.
- The forecast annual rate of increase in operating expenditure of around 1.4 per cent—due to expected wage growth and network expansion—is shown separately to the base level forecast.
- At the time of releasing our Draft Plan, we did not identify any step changes, this is not surprising because it was early in the process and any step-up in costs are not known until quite late. Now we have become aware of several step changes which we expect to incur in the 2021-26 period. A summary of the step changes are outlined in the Appendix to this document.

We believe that our forecast operating expenditure represents the level of funding necessary to achieve the requirements under the NER to efficiently meet our obligations and customers' expectations and to promote their long-term interests.

Further information on our operating expenditure proposal can be found in Attachment 06-01 to 06-08.

07

We use regulatory **methods** to determine our **revenue needs**

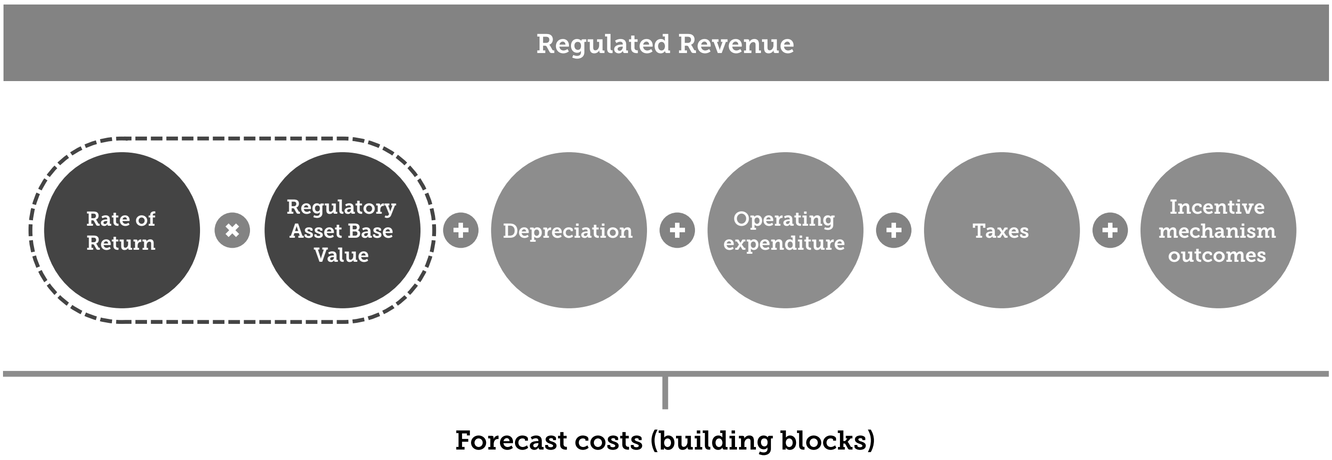
7.1 Network Services

Revenue building blocks

As we are a regulated business, we are required to make an estimate of how much revenue we will need to cover our costs, invest for the future and provide a return to our shareholders.

Our Proposal for the next regulatory period is calculated using the AER's post-tax revenue model (PTRM). In this model, total revenue is estimated as the sum of a number of different types of costs we know as 'building blocks'.

Figure 7.1 The revenue building blocks



By adding the above building blocks together, we derive our proposed total requirement for annual revenue during the next regulatory period. We receive this revenue from our customers' electricity retailers by way of network tariffs.

Our regulated asset base (RAB) consists of the assets we have historically invested in that are not fully depreciated and our investment in the network made through our 2021-2026 capital program. By keeping our capital expenditure efficient, we only recover what we really need in the revenue forecast.

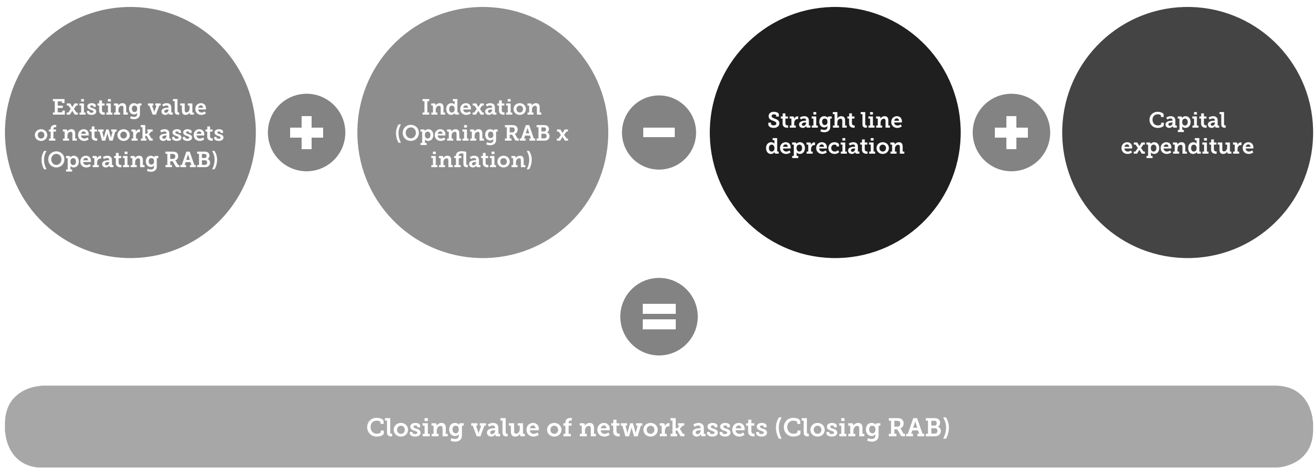
Return on Capital

Our RAB is the value of all the assets we use in providing distribution services. This value represents the—as yet—unrecovered capital investment we have made in the past, to provide services to our customers now and in the future.

The value of the RAB changes over time. It increases with every investment in new assets, and falls as we depreciate existing assets over time. We also index the RAB in accordance with regulatory processes. Finally, when customers make capital contributions to these assets, or we dispose of them, the proceeds are subtracted from the overall value.

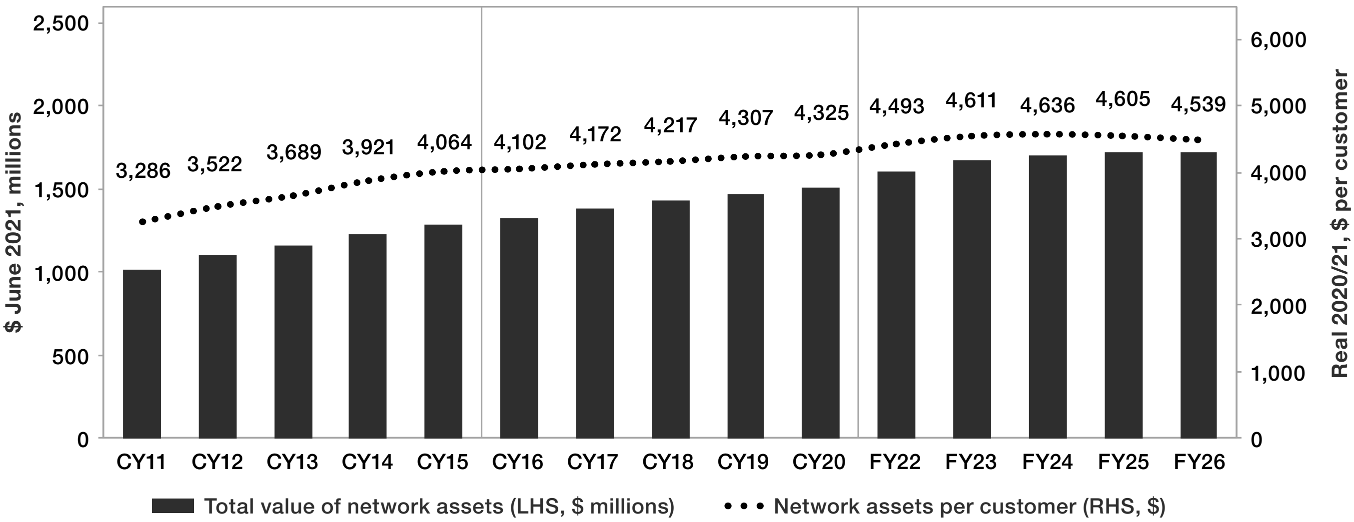
To calculate the opening value of the RAB for the next regulatory period, we have used an approach that is consistent with the NER, and the AER's 'roll-forward' models. These models capture our actual and forecast net-capital expenditure and depreciation.

Figure 7.2 How the RAB is calculated



We estimate that the value of our asset base at the start of the next regulatory period will be $1.6B and that it will increase to $1.7B by the end of the period. This increase is principally due to capital expenditure and escalation. Over the long term, we expect the RAB per customer to decrease. Even now we are seeing the trend changing with the rate of increase slowing to 4.9 per cent from the end of the current regulatory period to the end of the next, this is lower than the increase in our customer numbers of 9 per cent over the same period.

Figure 7.3 Network RAB trend



We use the term Rate of Return to represent the return on the cost of borrowing to raise the funds we need to be able to invest in new assets. The RAB is, in effect, the outstanding balance of money we owe to those who financed our capital expenditure, and therefore the rate of return covers the cost of borrowing that money.

For the next regulatory period we have incorporated the approach to determining the rate of return as outlined in the AER's latest Guideline using the parameters outlined in Table 7.1.

Table 7.1 Calculating the rate of return

Parameter	Proposal
Return on equity	4.70%
Return on debt	4.87%[1]
Inflation	2.37%
Leverage	60%
Gamma	58.5%
Corporate tax rate	30%
Nominal Vanilla Rate of Return	**4.80%**[1]

1. First year value

Depreciation–return of capital

We do not recover our capital expenditure in the year we spend because of its lumpiness and its benefits are realised over many future years. Instead, we recover these costs over the economic life of these assets. This recovery of investment is referred to as return of investment.

We calculated this allowance using an approach that is consistent with the NER and also the AER's PTRM. In addition to depreciating assets due to ageing, the AER's PTRM also increases their value to account for the impact of inflation.

Operating expenditure

Operating expenditure is a significant part of our building block revenue. We have provided an outline of our operating expenditure forecast in chapter 6.

Incentive scheme arrangements

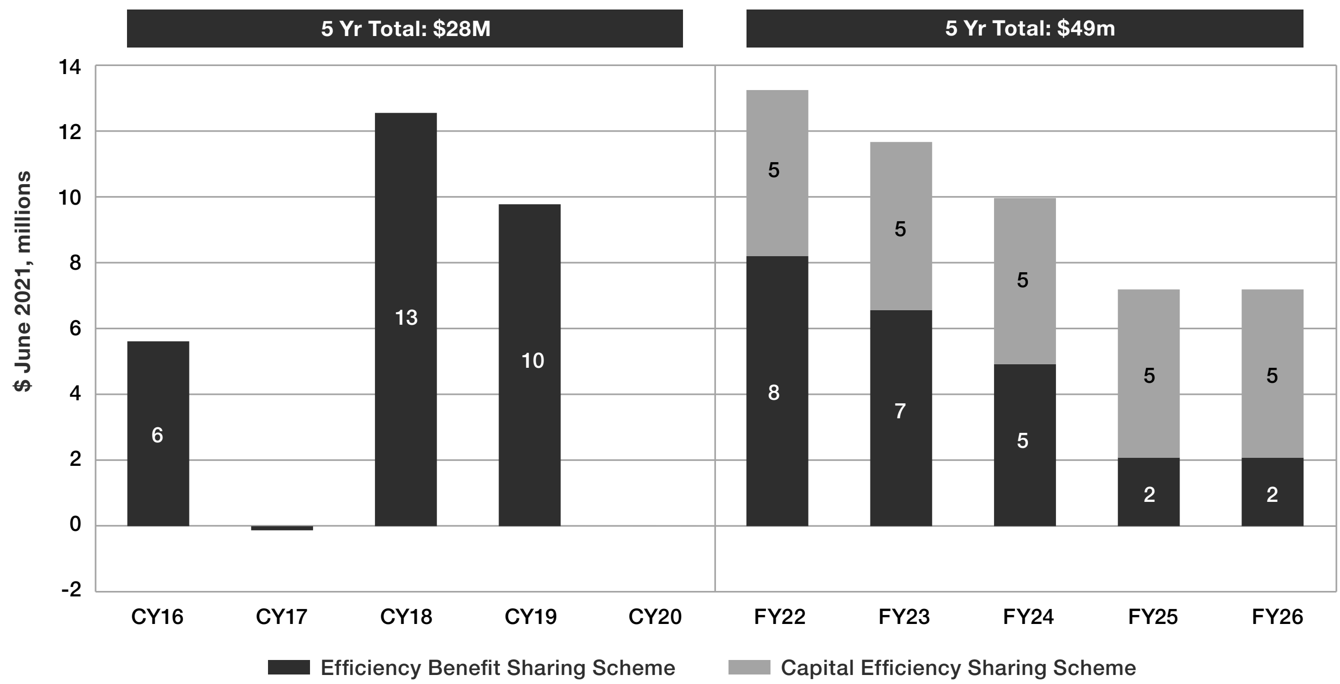
The AER applies a range of incentive schemes to electricity distribution businesses. As a result of our performance against these incentives, we will either receive a reward or penalty in our revenue. For some schemes, the reward or penalty is received within a regulatory period, for other schemes, the rewards and penalties are recovered in the next regulatory period.

The list of incentive schemes and their application is outlined as follows:

- Built into the forecast building block revenue:
  - Efficiency benefit sharing scheme **(EBSS)**
  - Capital expenditure sharing scheme **(CESS)**
  - Demand management incentive scheme **(DMIS)** and demand management innovation allowance mechanism **(DMIA)** and
- Applied during a regulatory period:
  - Service target performance incentive scheme **(STPIS)**
  - Victoria F-factor scheme.

For the EBSS and CESS schemes, our plan is to incorporate our performance from the current regulatory period into our revenue allowance for the next regulatory period. The rewards to be reflected in our revenues in the next regulatory period—attributed to Opex and Capex savings in the current regulatory period—are outlined in Figure 7.4.

Figure 7.4 CESS and EBSS incentive components of the building block model



Corporate income tax

This allowance represents what we forecast our income-tax liabilities to be over the next regulatory period.

To calculate this allowance, we have used the value of imputation credits determined by the AER as a part of the rate of return guideline. The amount of corporate tax allowance is estimated by multiplying the corporate tax rate by taxable income.

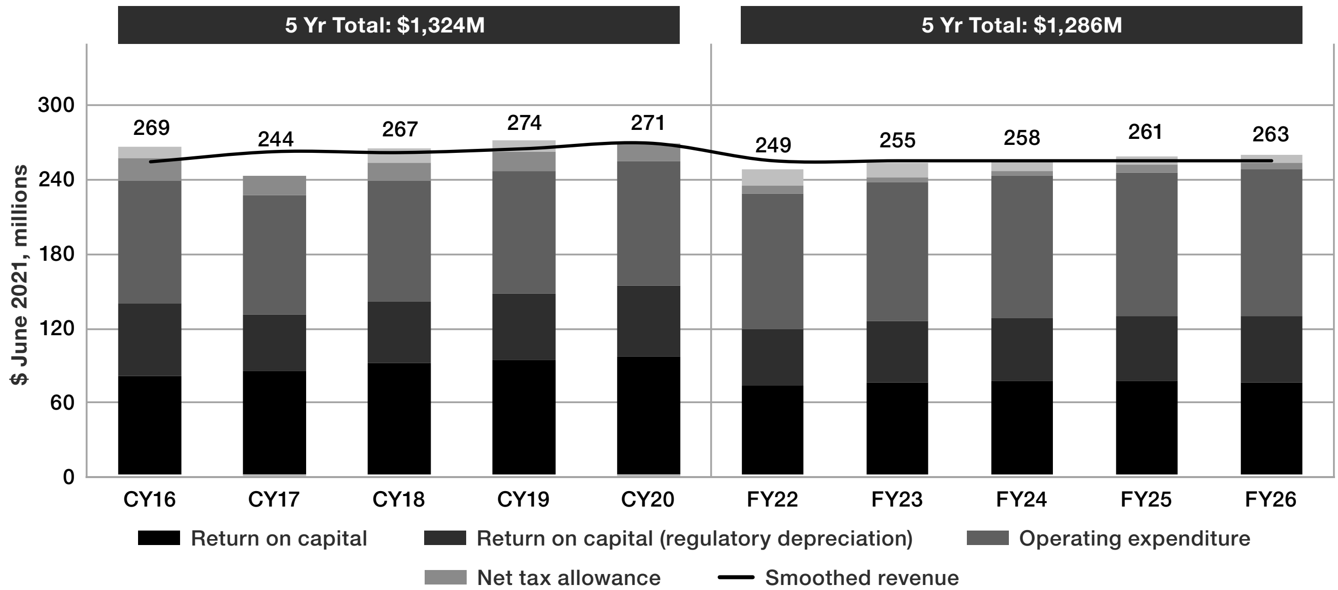
Proposed shared-asset revenue reduction

A small number of assets we use to provide regulated services are also used to provide unregulated services. The adjustment for shared-asset revenue reflects the benefits we and our customers received from these assets over the current regulatory period.

Total revenue requirement

As a matter of process we bring these building block components together to determine our revenue requirement. At this point, the amounts can be quite varied from year to year and so, to avoid volatility, we undertake a process of smoothing to flatten out our revenues. To smooth revenues, we make adjustments to total revenues between years by taking into account the time value of money, but making sure the present value is unchanged. Based on this approach, we are seeking $1,286 million in revenue over the next regulatory period to deliver the program outlined in this Proposal.

Figure 7.5 Total network revenue requirement



7.2 Alternative Control Services

Along with Network Services that are central to the supply of electricity, we provide additional customer-specific services on request.

These services are known as alternative control services and include:

- Metering services
- Auxiliary metering service
- Connection services
- Connection management services
- Ancillary network services
- Public lighting services

We propose to apply fixed prices for some services where the scope and cost of providing the service do not vary significantly between jobs. For the remaining services, prices will be quoted using labour rates that are approved by the AER and adding the costs we incur for materials and contractors.

Metering

What AMI delivers–previous, current, future

AMI gives us data and real-time insight into the operation of assets on the grid, which helps us to improve the efficiency and reliability of the network. It also helps to keep power affordable by allowing us to target our capital spending more effectively.

The uptake of AMI meters—more than 98 per cent of our customers have AMI meters—is the key to unlocking the benefits of a smart grid. This significantly improves the way we forecast demand and the load on the network. In addition, we can improve our responsiveness to supply outages through automated outage notifications, reduce hazards—through remote identification of poor connections—and detect if a customer has a faulty meter that needs replacing.

When it comes to smart meters, we are constantly finding new and innovative ways to realise the benefits, and will continue to embrace the technological advances that accompany them. We also plan to leverage the infrastructure provided by the AMI program to develop the kind of smart, robust and efficient network we will require to meet ever-changing customer needs.

We have been developing and applying smart technologies to the electricity network over many years. Our focus for the next regulatory period will be on:

- Refining a roadmap to guide the development of operational technologies.
- Data analytics—to analyse network data (AMI data, SCADA data) to develop insight for more efficient and effective management and operation of the electricity network.
- Demand management and non-network alternatives—to develop the capability for us to undertake economic alternatives to network investment to meet customer demand—through initiatives like demand response, embedded generation, energy storage and other technologies.
- Delivering network benefits by leveraging AMI through incremental investment in our AMI meter firmware/backend system upgrade; and integration with an Outage Management System—to deliver improved operational efficiency, reliability and quality of supply, enhanced asset safety, and better customer service.
- Enable the uptake of new energy services offered by other market participants—customer participation in the energy markets—for example, peer-to-peer trading.
- Facilitate the connection of DER—address the current network issues caused by the connection of photo-voltaic systems, and trial technologies that will increase the hosting capacity of the distribution network for DER and electric vehicles.

Capital Expenditure

We currently have an obligation to provide metering services to customers who use less than 160MWh annually, and we expect this will continue into the next regulatory period. The majority of the capital expenditure required for metering relates to the additions and alteration of meters that we supply to customers. The scope includes:

- AMI meters—and the management of some legacy meters
- Advanced metering communications infrastructure
- A portion of IT systems that interface with these classes of meters.

Our forecast includes the additions, alteration, replacement and abolishment of metering assets. A proportion of the cost for the upkeep of the metering communication infrastructure—additions and replacement of access points, relays and battery packs—used for the collection of meter data, is also included.

We have forecast total capital expenditure for metering services of $21.3m for the next regulatory period.

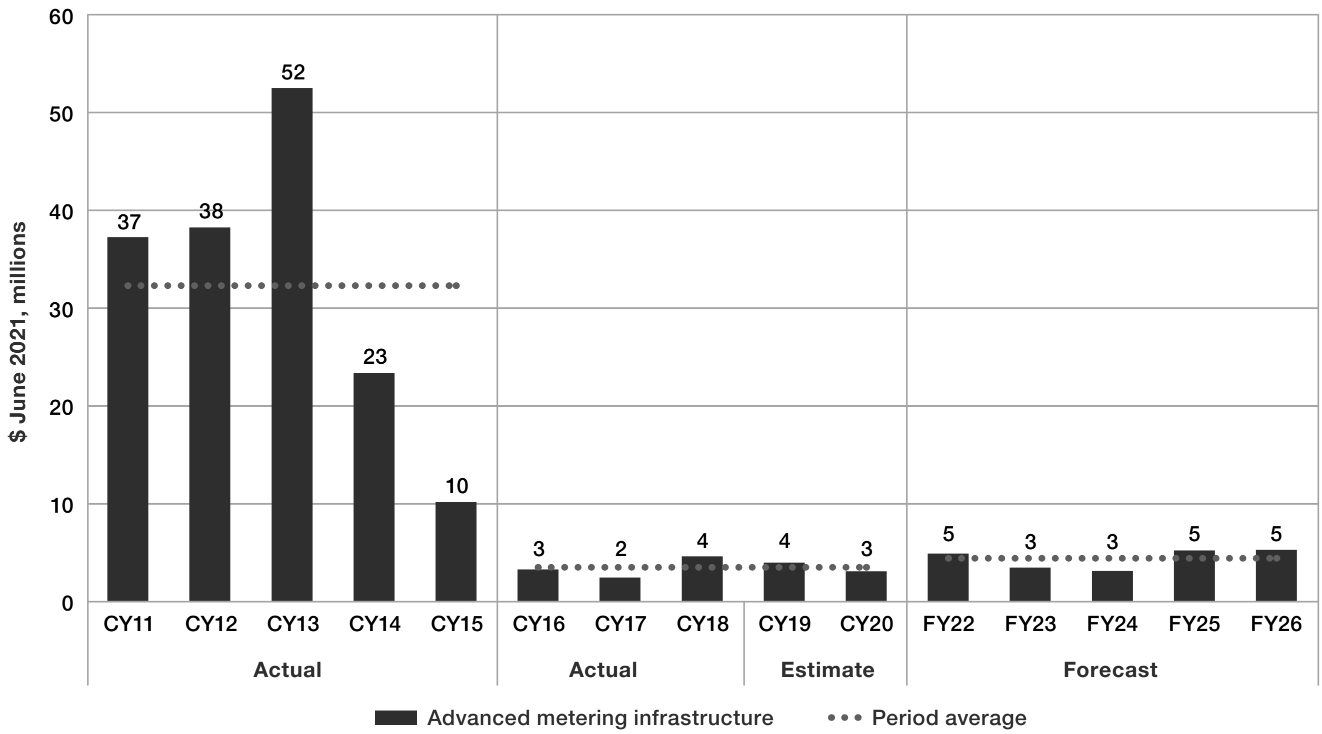
The amount we're proposing represents the prudent and efficient cost of providing ongoing AMI services to our customers. Figure 7.5 sets out our proposed forecast metering services capital expenditure for the next regulatory period.

The forecast metering asset-lifecycle expenditure continues to be low for the next regulatory period as our AMI rollout program was largely completed in June 2015 and, therefore, meters are still within the first 15 years of their asset life.

The rollout replaced the majority (>98%) population of legacy accumulation and interval meters. So we are forecasting a similar level of expenditure in the next regulatory period as in the current regulatory period, after taking into account the longer period for which we will be providing AMI meters.

We do not expect that AMI meter family failures will occur in the next regulatory period, and meter renewal will be limited to random failures caused by premature component failure or environmental influences.

Figure 7.6 Advanced metering infrastructure capital expenditure



Revenue Requirement

Similar to our approach for calculating Network Services revenue in the next regulatory period, we will use the AER's building block model to determine our revenue requirement for AMI services. The main blocks include:

- Return on Capital—in determining the Rate of Return for metering services, we use the same approach and rate of return as for Network Services.
- Depreciation—we will use a standard asset life of five years for IT and communication systems and fifteen years for meters, to depreciate equipment.
- Operating expenditure—we will use the base, step and trend approach.
- Corporate income tax—we will apply the same approach as has been used in the current regulatory period.

Figure 7.6 outlines the total building block revenue for AMI services in the next regulatory period.

Connection services

In 2016, the Victorian Government made amendments to the National Electricity (Victoria) Act 2005 which required Victorian DNSPs to implement chapter 5A of the NER, and the AER's Connection Charge Guideline. In response, we have adopted the categories and terminology in that chapter.

For basic connections, where little or no augmentation of the network is required, we charge a fixed fee to cover the costs we incur in completing the work. This is in line with our responsibilities under chapter 5A of the NER and the AER's Connection Charge Guideline to Victorian Distributors.

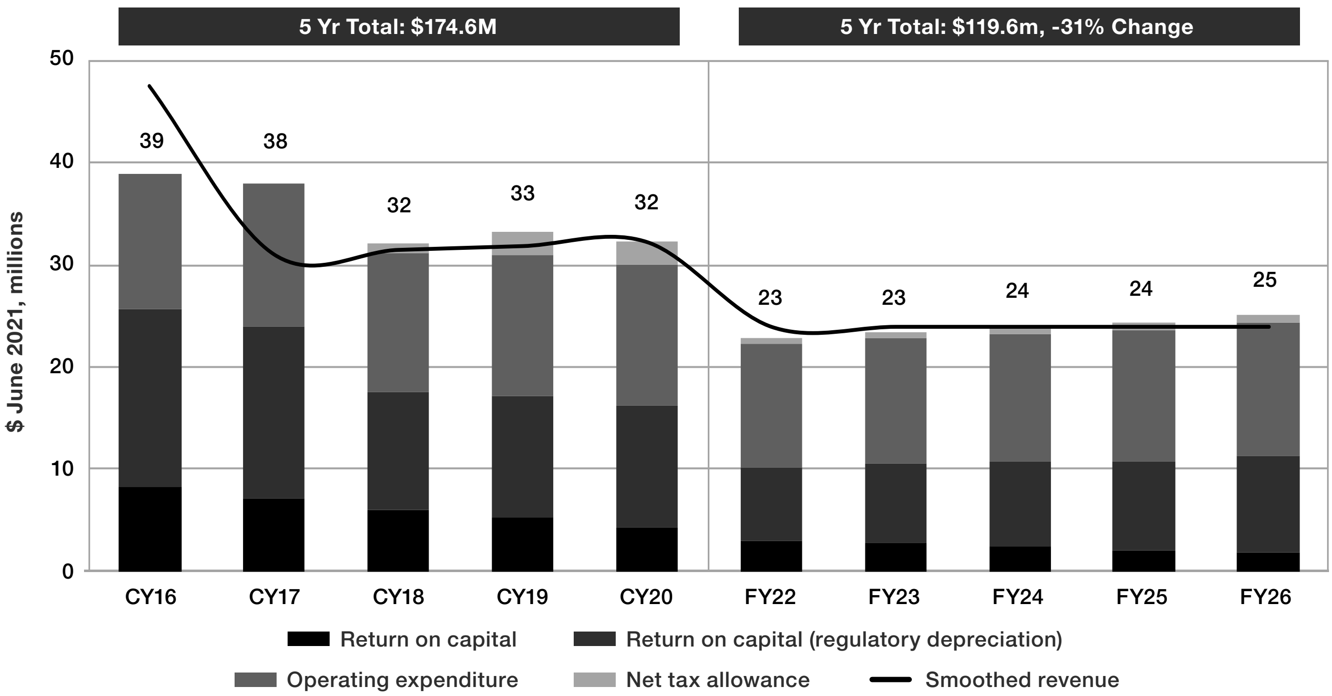
We charge a fixed fee for basic connections because the work we have to carry out, and the costs we incur in doing so, are relatively predictable.

Auxiliary metering services

In addition to metering services, we provide auxiliary metering services to customers on request. Auxiliary metering services include:

- Special meter read (i.e. off-cycle additional meter read)
- Remote meter reconfiguration
- Remote de-energisation and re-energisation
- Alteration of an existing metering installation
- Metering testing.

Figure 7.7 Total building block revenue for AMI services for the next regulatory period



Connection management services

Connection management services are activities associated with connections, such as:

- Field-based de-energisation and re-energisation
- Relocation of overhead connection
- Temporary disconnection and subsequent reconnection
- Upgrade of basic connection from single-phase to three-phase
- Enhanced connection services.

It should be noted that this is not an exhaustive list of the connection management services we provide.

Ancillary network services

These are a wide range of services that we provide, including security lights and the provision of data.

Public Lighting Services

Operating, maintaining and replacing existing lights

We provide public lighting services to 13 councils and VicRoads. In response to local council feedback, we are introducing three new types of energy efficient lights for major roads as potential replacements for existing old technology lights. We also consulted on whether we should incorporate decorative poles in our standard equipment list. However, we could not proceed as we could not reach a consensus amongst the customers. Instead, councils wanting decorative poles will continue procuring them on an 'as needs' basis.

Changes in the cost of labour, materials, the failure rate of lights and an adjustment to the time taken to replace and maintain lights—to better reflect the actual duration of that work—have all been taken into account in the preparation of our forecast for public lights.

The Minamata Convention

The Minamata Convention is an international convention designed to reduce the use of mercury. This has implications for our public lighting service because mercury is present in some of the globes we use. At the time of developing this proposal, Australia has not yet ratified the convention—which would ban the import and manufacture of mercury vapour lamps from 1 July 2021— but we expect it will by the time the next regulatory period commences. Going forward, when a mercury vapour lamp fails, we will be replacing the whole luminaire with an LED version. Our public lighting customers are supportive of this approach.

New public lights

We will make offers to customers requesting new public lighting. Although the classification of this service has changed from a negotiated service to an alternative control service, our approach to making offers will not change once we enter the next regulatory period.

7.3 Negotiated Services

JEN also has a process in place for providing negotiated services, The negotiation framework for negotiated services can be found at Attachment 07-10. JEN does not propose any negotiated services during the next regulatory period, however, the negotiation framework remains in place for completeness.

7.4 More information on our revenue proposal

More information on the revenue requirement for our network, metering and other alternative control services can be found in Attachments 07-01 to 07-09 and 07-11 to 07-34.

08

We seek to **recover revenues** efficiently and **fairly**

8.1 Standard Control Services

To recover our building block revenue, we develop network prices that we use to charge a customer's retailer. Retailers then bundle network and other costs and charge these on to their customers.

Future-ready pricing structures

Currently, most households and small businesses pay (via their retailer) for the use of the network as a combination of a fixed charge and a variable charge, which increases with the more electricity they use—we call this a single rate pricing structure. The variable charge within the single rate pricing structure does not take into account when customers actually use electricity. So it does not signal to customers the additional cost of consuming electricity at certain times of the day when the demand on the network is highest and the cost to provide network services is the most expensive.

We also currently offer households and small businesses the choice of:

- A time of use pricing structure – where prices are relatively higher at peak times and cheaper at off-peak times—this pricing structure provides a signal to move electricity consumption from peak to off-peak periods.
- A demand pricing structure – which, compared to the single rate pricing structure, has a cheaper variable charge and a demand charge based on their maximum monthly consumption in a peak half-hour—this pricing structure provides a signal to customers to spread out when they use major appliances like air conditioners and dishwashers.

In the future, customers are likely to use the electricity network a lot differently to how they have in the past. There are several future trends that impact on pricing structure design:

- Continued growth in air-conditioner load, exacerbating the early evening peak
- Emergence of electric vehicles, which could exacerbate the early evening peak
- Future take-up of home batteries with solar PV allowing use of solar generation to be shifted to any period
- Continued new connections driven by population growth.

The first two trends suggest peak pricing in the early evening should be considered to encourage less usage during that time, to reduce future augmentation investment. The third trend suggests peak pricing in the early evening and off-peak pricing around midday to encourage self-use of solar generation to be shifted from midday to early evening.

We detail our approach to pricing in our tariff structure statement (Attachment 08-01) and our tariff structure statement explanatory statement (Attachment 08-02). The following sections summarise the key elements of our tariff structures statement.

What stakeholders told us

Over the past two and a half years, the Victorian electricity distributors have engaged jointly with numerous stakeholders on the future of network pricing structures.

Through this process, we have heard:

- **Future network forum 1 (1 Nov 2017)**—Network pricing reform should reduce cross-subsidies and provide appropriate price signals. The pricing principles we should seek to meet are: simplicity, economic efficiency, equity, affordability and adaptability, with particular support for, and emphasis on, simplicity
- **Future network forum 2 (18 Apr 2018)**—Network pricing structures should be targeted at retailers but with the impact (potential or actual) on end-customers in mind
- **Future network forum 3 (20 Mar 2019)**—Majority support for re-assignment of all customers to a new simplified two-rate time of use pricing structure with a carve-out for identifiable vulnerable customers (those on life support and with medical cooling concessions). However, there remained some strong concern about the impacts on other harder-to-identify vulnerable customers and some preference for assignment policies that better target “non-vulnerable” customers. Stakeholders also emphasised the importance of communicating change and to be clear on the case for change.

We shared what we had learned from the first two DNSP pricing forums with our People’s Panel. They expressed support for network pricing structures that better signalled the cost of operating the electricity network, recognising that this would lead to lower costs in the long term.

The People’s Panel members indicated a slight preference for the ‘demand’ price structure but noted that a time-of-use price structure, which is simpler and more readily understood, may also be acceptable. Importantly, the People’s Panel supported customer choice. Customers should be able to opt-out from any pricing structure to one that better meets their needs.

Our proposed approach for households

We are proposing to retain the three pricing structures noted above; single rate, time of use and demand, so that retailers can mirror our structures and offer choice to customers. We will introduce a new simplified time of use price structure that will be our default price structure for households. This will have a 3pm to 9pm (local time) peak period, every day of the year.

While all three price structures are available to all households, the key change is how we will assign customers to the new time of use price structure.

We recognise that customer interactions with a retailer present a key opportunity for communicating price options. Therefore, residential customers requesting the following services through their retailer will be placed on the new time of use network pricing structure:

- New connections
- Three-phase meter upgrades
- New solar and/or battery installations.

We would also like to include owners of electric vehicles although currently lack a credible means to identify these customers. Should a register of customers who purchase electric vehicles or other robust means of identifying an electric vehicle customer emerge over the 2021-26 period, we would also seek assign these customers to the new time of use tariff. In the absence of this information, we will work with other stakeholders to encourage electric vehicle owners to opt in to the new time of use tariff.

We consider that the upfront costs of these activities would materially decrease the likelihood that vulnerable customers would be included in this approach to tariff assignment.

With the introduction of our new time of use tariff, we will close the current three-rate “flexible” time of use tariff to new entrants.

Our proposed approach for small business

We already have around 37 per cent of small business customers on some form of time of use price structures. On average, small businesses are therefore more likely to respond in line with efficient network investment than our household customers, of which only around 6 per cent of our customers are on a time of use price structure.

Also, we need to be mindful of:

- Our small business customer peaks generally occur earlier than our system peaks, so our driver is to provide price signals that reduce localised peaking of substation and transformers that service small businesses.
- The impacts on small businesses who may have limited choice about when to consume electricity to carry out their business and serve their customers—for example, shops that open during business hours or restaurants that open at mealtimes. It's difficult to envisage some small businesses being able to materially respond to a price signal to reduce their bill impact.
- There is limited evidence that small businesses actively engage with the energy industry for us to confidently rely upon those who would be better off on another tariff to actively seek change.

However, we consider it is important to continue to improve our approach to pricing for small businesses. We consider an assignment regime predicated on either already being a time of use customer or having a pre-existing reason to contact the retailer—for the same reasons as provided for households—to be appropriate.

We are therefore proposing to have only one time of use price structure for small businesses consuming under 40MWh per annum (there are currently 31 available across the Victorian DNSPs), and reduce the length of our peak period to be 9am to 9pm (local time) to make it more reflective of our costs. This involves moving a number of customers on legacy time of use price structures onto the one new time of use structure.

Additional detail is found in our tariff structure statement (see Attachment 08-01).

For our large business customers

Some of our large customers told us they were experiencing cost pressures for energy and asked us to find ways to help them.

In response, we intend to change our approach to measuring billable demand from ratcheted to rolling. This will mean we measure demand over the most recent 12 months. By making this change, our customers have the opportunity to respond by, for example, implementing customer-side equipment to reduce their overall network charges. They could also lower their network bills automatically just by adapting to troughs in business cycles.

Complementary measures

We want to help customers understand how they can respond to changes in network pricing structures and how to take control of their electricity bills. To complement our new approach to tariffs we are focusing on what literacy programs, technology rebates, energy efficiency programs and peak time rebates will make most sense for our customers over the next period.

Rebates are another way we can supplement pricing structures and our People's Panel supported this. We have explored ways to do this in the past—see Figure 8.2—and will continue to do so in the future.

Figure 8.2 Our Power Changers program

The trial provided the community with an opportunity to consider how electricity consumption impacts network capacity and how small changes at home can have positive long term implications on their bills. Learnings from the trial have been used to support our 2019/2020 residential demand response program.

The Power Changers trial was an opportunity to:

- Educate customers about network supply and demand
- Provide customers with valuable personalised insights from their smart meter data
- Provide home owners with valuable energy saving and cost cutting advice
- Help raise money for local community groups and schools
- Provide valuable insights into customer behaviours
- Test diverse participant motivations
- Enable networks to keep investment and costs down without compromising reliability.

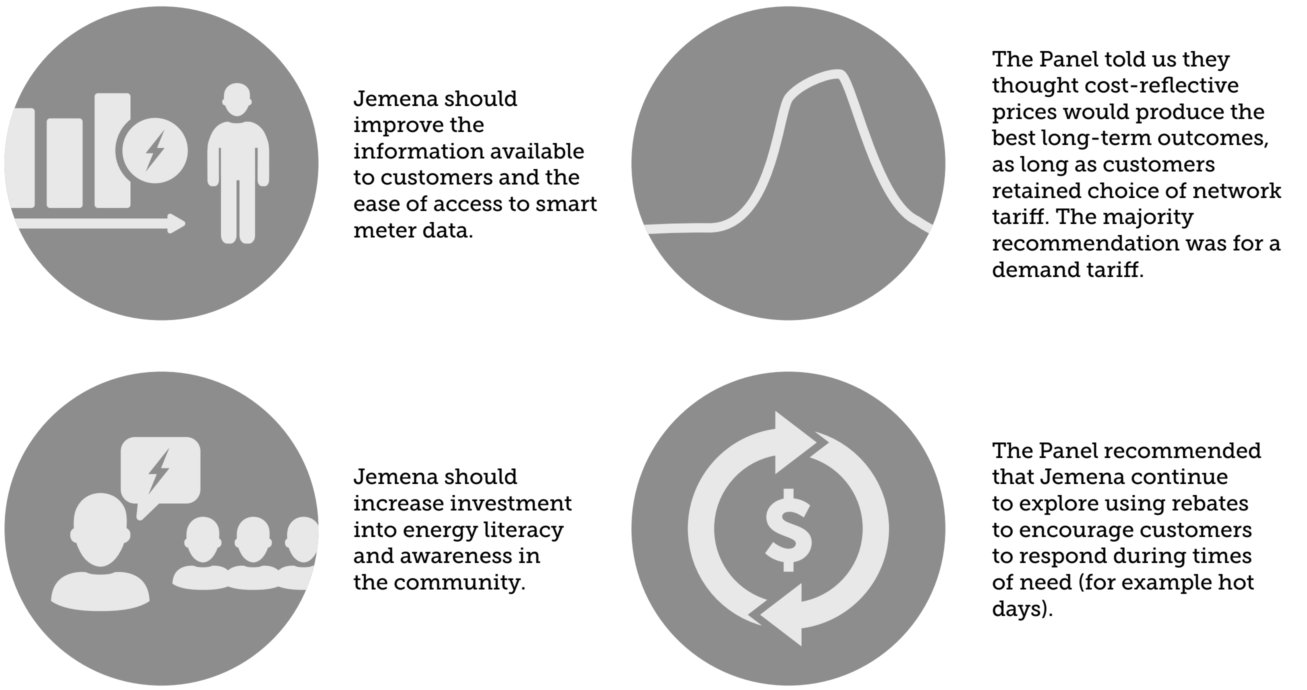
Trial findings have been published by Victorian Government and the program has received national and international industry recognition;

- Runner up 2018 Edison Award, Edison Electric Institute (USA)
- Winner 2018 Digital Customer Innovation Project of the Year, Digital Utility Awards
- Winner 2018 Technology Project of the Year, Asian Power Awards
- Runner up 2018 Industry Innovation Award, Energy Networks Australia Awards

During the current regulatory period, we developed a Community Grid project called 'Power Changers', which we delivered to a selection of customer. Its aim was to manage network risks by helping households reduce their peak demand with renewable technologies and incentives. Through the program, we were able to show those who participated that, during hot days, their electricity consumption increased threefold, and we were able to bring that consumption down through a combination of education and reward.

How our panel members have informed our pricing structure plans

Figure 8.3 People's panel recommendations driving household network pricing



While the majority of our Panel recommended our default household tariff be a demand tariff, we have proposed a two-rate demand tariff. A strong stakeholder preference and, therefore, a key driver for our household proposal is to provide a consistent position across Victoria. This has required us to bear in mind the customer views heard by the other Victorian electricity distributors and what we have heard from customer advocate groups within our joint forums. The strong preference coming out of those engagements was for a simple time of use tariff.

This position is not far removed from our Panel's position. We consider a two-rate time of use tariff to still be consistent with the preferences of the Panel because they supported:

- the principle of simplicity—many Panel members felt that time of use tariffs were more readily understood than demand tariffs
- movement toward improved cost reflectivity—which our movement away from a single-rate tariff to a default time of use tariff would provide.

We are also providing pricing-related materials aimed at improving energy literacy in response to the recommendation of the Panel.

Price impacts

Our Proposal will result in bill decreases of 14% over the 2020-25 period, or $320 for a typical residential customer, when compared to their bills within the current period (see Figure 8.4).

Figure 8.5 provides a long-term view of a typical residential customer's network bill. With an expected network bill of $448 or $399 in 2021 dollars, customers in 2026 will enjoy they lowest network bill relative to their incomes in 15 years.

Figure 8.4 Network bill impacts of our 2021-26 regulatory proposal

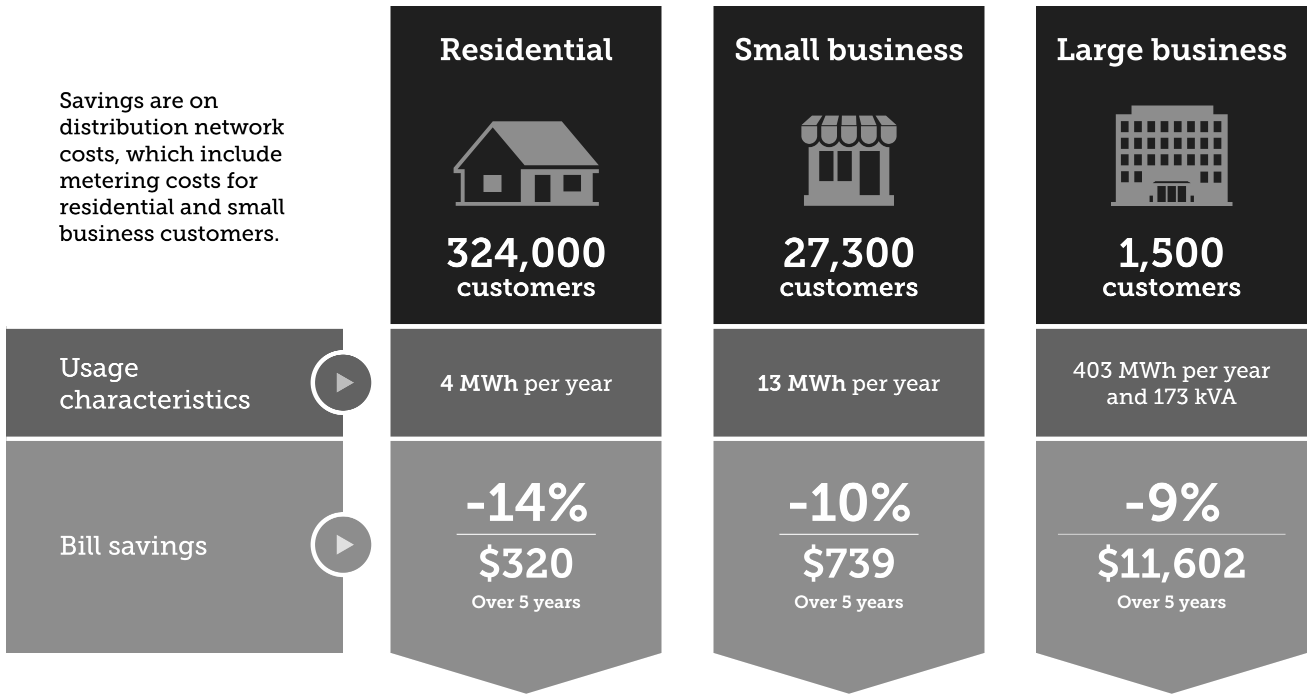
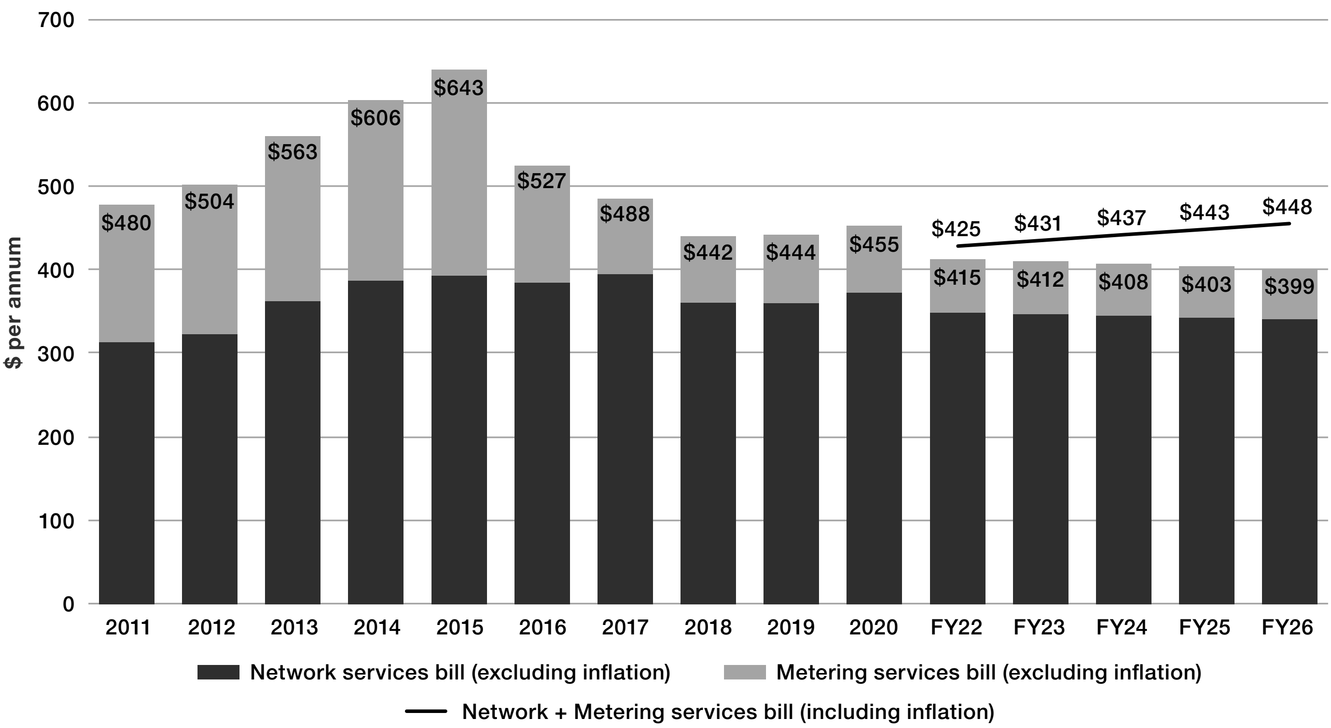


Figure 8.5 Typical residential customer network services and advanced metering charges



8.2 Alternative Control Services

AMI Pricing

Our approach to setting prices for AMI services is quite simple and follows the approach we've used in the past, which adheres to a range of regulatory compliance requirements. We simply take the revenue that we calculated we will require to provide AMI services and allocate it out to the four-meter categories we provide.

The revenue we need to provide metering services will reduce by 20 per cent. This decrease is driven by several factors including a lower metering asset base (with the investment being mostly recovered since the rollout in 2014), a lower rate of return and lower operating costs due to efficiencies we have found. This will be reflected as an equivalent reduction in prices for our residential and small business customers. Large business customers have metering services provided by competitive metering providers and are not managed by us.

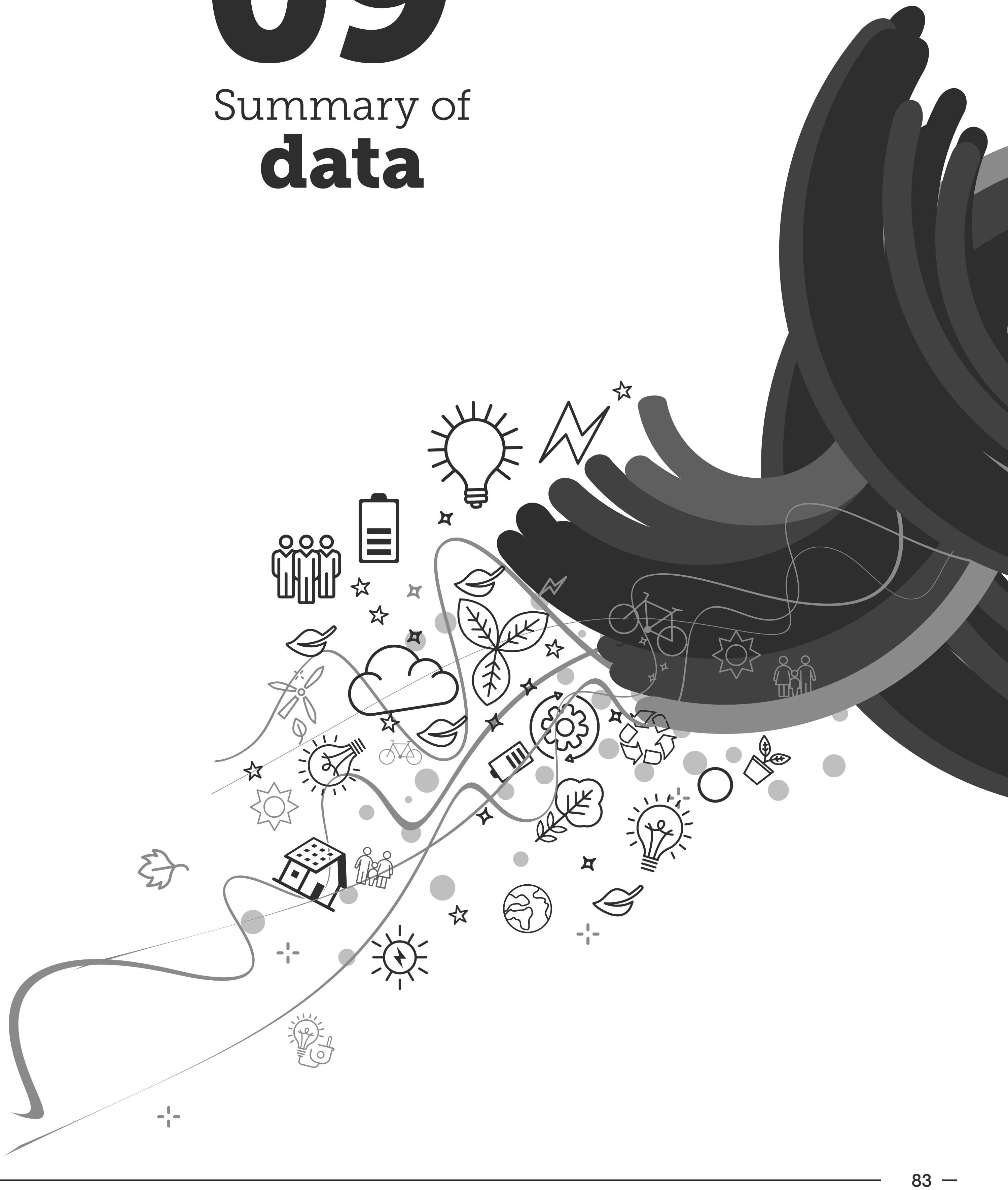
Other Alternative Control Services

We propose to apply fixed prices for some alternative control services where the activities do not vary significantly from job to job. For the remaining services–where the variability in activities and costs is more pronounced, prices will be quoted by way of a cost pass-through using the labour rates approved by the AER, along with material and contractor costs.

8.3 More information on revenue recovery

More information on how we recover revenue can be found in Attachments 08-01 and 08-04.

09
Summary of **data**



Standard control services tables

Revenue requirement, building block components ($ June 2021, millions)

Building blocks	FY22	FY23	FY24	FY25	FY26	Total
Return on capital	72.8	74.4	75.6	75.2	73.9	371.9
Regulatory depreciation	45.9	50.6	52.1	54.8	55.9	259.4
Operating expenditure	110.5	112.8	115.7	117.7	119.8	576.6
Incentives (including shared asset adj.)	13.3	11.8	10.1	7.3	7.3	49.8
Tax	6.9	5.3	4.3	6.0	5.9	28.5
Total	**249.4**	**254.9**	**257.9**	**261.1**	**262.9**	**1,286.2**

Forecast factors

Forecast factors	FY22	FY23	FY24	FY25	FY26
Maximum demand (MW)[1]	970.3	977.8	983.9	988.3	995.6
Maximum demand (% change pa)	1.15%	0.78%	0.62%	0.45%	0.74%
Energy delivered (GWh)	4,506.3	4,577.5	4,605.3	4,633.9	4,665.0
Energy delivered (% change pa)	1.46%	1.57%	0.61%	0.62%	0.67%
Customer numbers (#)	361,445	366,748	372,108	377,564	382,785
Customer numbers (% change pa)	1.46%	1.46%	1.45%	1.46%	1.37%

1. ACIL Allen, Summer peak demand, 50 POE

Operating expenditure ($ June 2021, millions)

Operating expenditure	FY22	FY23	FY24	FY25	FY26	Total
Base	99.1	99.1	99.1	99.1	99.1	495.6
Step changes	6.7	7.5	8.9	9.4	10.0	42.4
Trend	2.3	3.8	5.3	6.8	8.3	26.4
Other specific items (incl DRC)	2.4	2.4	2.4	2.5	2.5	12.1
Total	**110.5**	**112.8**	**115.7**	**117.7**	**119.8**	**576.6**

Operating expenditure – trend factors (%pa)

Operating expenditure – trend factors	FY22	FY23	FY24	FY25	FY26
Real labour escalation	0.99%	1.02%	1.07%	1.08%	1.08%
Productivity factor	-0.50%	-0.50%	-0.50%	-0.50%	-0.50%
Scale escalation	1.20%	1.31%	1.32%	1.27%	1.27%
Overall rate of change	**1.29%**	**1.42%**	**1.46%**	**1.41%**	**1.42%**

Operating expenditure – other specific items ($ June 2021, millions)

Operating expenditure – other	FY22	FY23	FY24	FY25	FY26	Total
Guaranteed Service levels	0.2	0.2	0.2	0.2	0.2	0.8
Electricity Levy for Energy Safe Victoria	1.4	1.4	1.4	1.4	1.4	6.9
Debt raising costs	0.8	0.9	0.9	0.9	0.9	4.4
Total	**2.4**	**2.4**	**2.4**	**2.5**	**2.5**	**12.1**

Return on capital ($ nominal, millions)

Return on capital	FY22	FY23	FY24	FY25	FY26	Total
Opening regulated asset base[1]	1,551.1	1,662.2	1,772.0	1,850.6	1,909.1	
Rate of return (%pa)	4.80%	4.69%	4.58%	4.46%	4.35%	
Total	**74.5**	**78.0**	**81.1**	**82.6**	**83.0**	**399.2**

1. Nominal values applied to this table to align with the PTRM calculations

Capital expenditure ($ June 2021, millions)

Capital expenditure	FY22	FY23	FY24	FY25	FY26	Total
Replacement	45.9	41.0	40.3	41.1	42.6	210.9
Connections	46.3	41.4	43.8	45.2	41.3	218.0
Augmentation	33.4	57.1	27.7	18.2	10.1	146.5
Non-network (IT)	30.5	21.9	21.9	12.7	8.8	95.7
Non-network other	6.8	2.6	3.0	2.5	3.3	18.2
Capitalised overheads	18.7	19.3	18.1	17.8	17.4	91.2
Total gross capital expenditure	**181.6**	**183.4**	**154.7**	**137.5**	**123.4**	**780.5**
Customer contributions	32.9	29.6	30.6	30.5	29.4	153.0
Net capital expenditure	**148.7**	**153.7**	**124.2**	**107.0**	**94.0**	**627.6**

Regulated asset base ($ nominal, millions, unless stated otherwise)

Regulated asset base	FY22	FY23	FY24	FY25	FY26
Opening RAB	1,551.1	1,662.2	1,772.0	1,850.6	1,909.1
Net capital expenditure	158.1	162.8	134.5	118.6	106.6
Inflation on opening RAB	36.7	39.3	41.9	43.8	45.1
Depreciation	-83.7	-92.4	-97.8	-103.9	-108.0
Closing RAB	1,662.2	1,772.0	1,850.6	1,909.1	1,952.8
Closing RAB (2020/21 Real)	**1,623.8**	**1,691.1**	**1,725.3**	**1,738.7**	**1,737.4**

Rate of return

Component	Amount
Nominal risk-free rate	1.04%
Market risk premium	6.10%
Equity beta	0.6
Return on equity	4.70%
Return on debt[1]	4.87%
Gearing	60.00%
Nominal vanilla rate of return[1]	4.80%
Forecast annual inflation	2.37%

1. First year value

Regulatory Depreciation ($ nominal, millions)

Depreciation	FY22	FY23	FY24	FY25	FY26	Total
Straight-line depreciation	83.7	92.4	97.8	103.9	108.0	485.8
Less inflation on the opening RAB	-36.7	-39.3	-41.9	-43.8	-45.1	-206.8
Regulatory depreciation	**47.0**	**53.0**	**55.9**	**60.2**	**62.9**	**279.0**

Incentive schemes (including shared asset adjustments) ($ June 2021, millions)

Incentive schemes (including shared asset adjustments)	FY22	FY23	FY24	FY25	FY26	Total
Efficiency benefits sharing scheme	8.1	6.5	4.9	2.1	2.1	23.6
Capital expenditure sharing scheme	5.1	5.1	5.1	5.1	5.1	25.6
Demand management incentive allowance	0.4	0.4	0.4	0.4	0.4	2.0
Shared assets	-0.3	-0.3	-0.3	-0.3	-0.3	-1.5
Total	**13.3**	**11.8**	**10.1**	**7.3**	**7.3**	**49.8**

Corporate tax ($ June 2021, millions)

Corporate tax	FY22	FY23	FY24	FY25	FY26	Total
Income tax payable	16.5	12.8	10.5	14.6	14.3	68.7
Less imputation credit value	-9.7	-7.5	-6.1	-8.5	-8.4	-40.2
Total	**6.9**	**5.3**	**4.3**	**6.0**	**5.9**	**28.5**

Revenue requirement ($ nominal, millions)

Revenue requirement	FY22	FY23	FY24	FY25	FY26	NPV
Unsmoothed revenue requirement	255.3	267.1	276.6	286.7	295.4	1,203.6
Smoothed revenue requirement	263.2	269.4	275.8	282.3	289.0	1,203.6
Revenue path (% pa)[1]	**-4.50%**	**2.36%**	**2.36%**	**2.36%**	**0.00%**	**N/A**

1. FY22 revenue path is calculated based on movement from CY20 maximum allowed revenue to FY22 smoothed revenue. FY23 to FY26 revenue path is set to hold prices flat in real terms.

Advanced metering infrastructure

Revenue requirement, building block components ($ June 2021, millions)

Building blocks	FY22	FY23	FY24	FY25	FY26	Total
Return on capital	2.8	2.6	2.3	2.0	1.7	11.4
Regulatory depreciation	7.1	7.7	8.1	8.5	9.3	40.8
Operating expenditure	12.3	12.5	12.8	13.0	13.3	63.9
Tax	0.7	0.6	0.7	0.8	0.8	3.5
Total	**22.8**	**23.4**	**23.9**	**24.3**	**25.1**	**119.6**

Forecast factors

Forecast factors	FY22	FY23	FY24	FY25	FY26
Customer number forecast	361,445	366,748	372,108	377,564	382,785
Customer number forecast (% change pa)	1.46%	1.46%	1.45%	1.46%	1.37%

Operating expenditure ($ June 2021, millions)

Operating expenditure	FY22	FY23	FY24	FY25	FY26	Total
Base	11.6	11.6	11.6	11.6	11.6	57.9
Step changes	-	-	-	-	-	-
Trend	0.7	0.9	1.2	1.4	1.7	5.9
Other specific items (incl DRC)	0.0	0.0	0.0	0.0	0.0	0.1
Total	**12.3**	**12.5**	**12.8**	**13.0**	**13.3**	**63.9**

Operating expenditure – trend factors (%pa)

Operating expenditure – trend factors	FY22	FY23	FY24	FY25	FY26
Real labour escalation	0.99%	1.02%	1.07%	1.08%	1.08%
Productivity factor	0.00%	0.00%	0.00%	0.00%	0.00%
Scale escalation	1.46%	1.46%	1.45%	1.46%	1.37%

Operating expenditure – other specific items ($ June 2021, millions)

Operating expenditure – other	FY22	FY23	FY24	FY25	FY26	Total
Debt raising costs	0.0	0.0	0.0	0.0	0.0	0.1
Total	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.1**

Return on capital ($ nominal, millions)

Return on capital	FY22	FY23	FY24	FY25	FY26	Total
Opening metering asset base[1]	60.3	58.2	53.7	48.2	44.5	N/A
Rate of return (%pa)	4.80%	4.69%	4.58%	4.46%	4.35%	N/A
Total	**2.9**	**2.7**	**2.5**	**2.2**	**1.9**	**12.2**

1. Nominal values applied to this table to align with the PTRM calculations

Capital expenditure ($ June 2021, millions)

Capital expenditure	FY22	FY23	FY24	FY25	FY26	Total
Meters	2.5	2.5	2.5	2.5	2.6	12.5
Information technology and communications	2.3	0.9	0.5	2.5	2.6	8.8
Total	**4.8**	**3.4**	**3.0**	**5.1**	**5.1**	**21.3**

Totals may not add up due to rounding.

Metering asset base ($ nominal, millions, unless stated otherwise)

Metering regulated asset base	FY22	FY23	FY24	FY25	FY26
Opening MAB	60.3	58.2	53.7	48.2	44.5
Net capital expenditure	5.1	3.6	3.3	5.6	5.8
Inflation on opening MAB	1.4	1.4	1.3	1.1	1.1
Depreciation	-8.7	-9.5	-10.0	-10.5	-11.5
Closing MAB	58.2	53.7	48.2	44.5	39.9
Closing MAB (2020/21 Real)	**56.9**	**51.3**	**45.0**	**40.5**	**35.5**

Rate of return

Component	Amount
Nominal risk-free rate	1.04%
Market risk premium	6.10%
Equity beta	0.6
Return on equity	4.70%
Return on debt[1]	4.87%
Gearing	60.00%
Nominal vanilla rate of return[1]	4.80%
Forecast annual inflation	2.37%

1. First year value

Regulatory Depreciation ($ nominal, millions)

Depreciation	FY22	FY23	FY24	FY25	FY26
Straight-line deprecation	8.7	9.5	10.0	10.5	11.5
Inflation on the opening RAB	-1.4	-1.4	-1.3	-1.1	-1.1
Regulatory depreciation	**7.2**	**8.1**	**8.7**	**9.4**	**10.4**

Corporate tax ($ June 2021, millions)

Corporate tax	FY22	FY23	FY24	FY25	FY26	Total
Income tax payable	1.6	1.4	1.7	1.9	2.0	8.5
Less imputation credit value	-0.9	-0.8	-1.0	-1.1	-1.1	-5.0
Total	**0.7**	**0.6**	**0.7**	**0.8**	**0.8**	**3.5**

Revenue requirement ($ nominal, millions)

Revenue requirement	FY22	FY23	FY24	FY25	FY26	NPV
Unsmoothed revenue requirement	23.4	24.5	25.7	26.7	28.2	111.8
Smoothed revenue requirement	24.5	25.0	25.6	26.2	26.9	111.8
Revenue path (% pa)[1]	**-14.58%**	**2.36%**	**2.36%**	**2.36%**	**2.36%**	**N/A**

1. FY22 revenue path is calculated based on movement from CY20 maximum allowed revenue to FY22 smoothed revenue. FY23 to FY26 revenue path is set to hold prices flat in real terms.


to hear,
listen
and think

Jemena
bringing energy to life