Regulatory proposal 2021–2026

Affordable, resilient, flexible

January 2020

Powercor AUSTRALIA

Good people in power

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1 Executive summary

Welcome to our 2021–2026 regulatory proposal, for the five-year period commencing 1 July 2021.

We are proud to present a regulatory proposal that offers our customers more value than ever before. We'll deliver more services to supply a network that is resilient and more flexible to the ways our customers are choosing to use electricity. And we'll deliver more for less; our annual charge will fall by $24 for residential customers and $68 for small business customers.

Our operating environment

We've never faced such a challenging operating environment—for example:

- more extreme climatic conditions are making it harder to deliver a safe and dependable network
- higher bushfire risks are driving requirements to install new Rapid Earth Fault Current Limiter (**REFCL**) technology and increasing insurance premiums
- a heightened level of cyber threat is underpinning the need to reinforce the systems supporting our network and protect customer data
- a more dynamic market is necessitating an improvement in network visibility and the provision of more data to market operators and our customers
- stricter environmental requirements are resulting in a more proactive approach to oil and noise management.

Our customers are also calling for more flexibility in the way they use our network—to both receive and export electricity—and for more information on their electricity interactions. And they rightfully expect a resilient network to meet their increasing use of electronic appliances and devices.

We are embracing these challenges while still promising to reduce our prices. Our customers can have confidence in our ability to deliver on our promises because we:

- already offer the lowest network charges of any rural distributor, and among the lowest of all distributors
- are Australia's most reliable rural network—available for over 99.97% of the year, or less than 2.5 hours of outages for an average customer
- are the most efficient distributor in Australia according to the Australian Energy Regulator's (**AER**) benchmarking
- provide the most highly utilised network, meaning we provide more services for less
- will pass on $326 million in savings to our customers from efficiencies we have delivered over 2016–2020.

In addition to our continued productivity- enhancing transformation activities, we will also lower our prices by leaning more on technology than ever before to drive further efficiencies and services.

This is also the most balanced proposal we've delivered. We've listened to our customers from across our region to deliver fairer service outcomes, and it is in this context we believe our regulatory proposal should be considered as a package rather than the sum of its parts. We're responding to our community by lowering bushfire risk, upgrading supply to support the dairy industry and accommodating new trends in distributed energy resources. In urban areas, we'll upgrade zone substations to accommodate customer growth and maintain network security and reliability.

We understand our regulatory proposal may not make it to your summer reading list, but we hope that everyone can take away something positive from it.

Every day we supply electricity to power our customers' activities

Replacement

Our replacement investment program ensures we can maintain our network to dependably power our customers' activities. This is supported by the following programs:

- $234 million for replacing more wood poles— we've changed our policies to better quantify degradation in wood pole strength as these poles age. This followed a review undertaken by Energy Safe Victoria (**ESV**). These changes will help to deliver a resilient network; a concept developed by our customers that combines safety and reliability.
- $48 million environmental management program—new environmental obligations will require us to proactively prevent waste and pollution impacts. Our forecast includes noise reduction and bunding programs at high-risk zone substations.
- $10 million transformer replacement program—we will replace three of our 146 transformers (and one regulator) to ensure we can maintain reliability. These transformers will each be more than 70 years old.

Our forecast asset replacement volumes are typically based on risk monetisation modelling, historical defect rates or historical replacement volume trends. This approach follows our asset management framework that aligns to international standards.

We have provided business cases and risk models to support 47% of our investment, particularly where our investment is higher than historical investment.

Connections

Our connections investment is needed to prepare the network for new customers. We are seeing:

- construction activity in the western corridor of Victoria continue to underpin strong residential and commercial connection demands in our region. We expect to connect 114,000 new households over the 2021–2026 regulatory period
- an influx of large scale renewable generation connections due to new regulatory requirements that are driving renewable generators to connect to the distribution (rather than transmission) network, higher wholesale electricity prices, the Victorian Government's Renewable Energy Auction Scheme and businesses seeking to deliver on commitments to be carbon neutral.

Our forecast is underpinned by independent and robust construction activity forecasts and historical investment needs.

We are preparing the network to be flexible to our customers' energy needs

Augmentation

Our augmentation investment ensures we can accommodate the ways our customers are choosing to use the network. This includes the following programs:

- $61 million for enabling solar—removing over 95% of the solar constraints (the equivalent output of around 2.4 large scale solar farms) to enable more customers to use their solar and support the Victorian Government's solar rebate. We have undertaken advanced modelling using our smart meters to ensure we only remove constraints where the benefits to our customers exceeds the cost.
- $173 million for REFCLs—a key program to reduce bushfire risk in our communities. While this program is mandated by the Victorian Government, we're working with ESV to deliver the same risk reduction at the lowest cost (such as along the Surf Coast, where we've considered a range of options to deliver a safe and efficient supply to the broader area). We also need to install additional REFCL assets at some zone substations to ensure existing REFCLs continue to operate as mandated as customer demand increases.
- $9 million to upgrade regional supply—our dairy farmers have made clear to us that regional infrastructure is not meeting their needs. This investment represents a small but important change in the balance of investment between urban and rural investment, recognising the contribution that rural small businesses make to our economy.
- $54 million to meet growing network demands—we'll establish new zone substations in Torquay and Tarneit (and Ballarat West as part of the REFCL program), undertake major zone substation upgrade works at Bacchus Marsh, and establish new feeders to alleviate supply constraints. We are balancing affordability by only upgrading sites where the value of the energy at risk exceeds upgrade costs and always implementing low cost solutions—such as load transfers and demand management—where possible.

Our demand driven forecasts are underpinned by a probabilistic planning approach under which we compare the cost to customers of an outage to the cost of an upgrade.

We have developed detailed business cases to explain the need for over 74% of our augmentation program.

Information and communications technology

It was only 150 years ago that illumination was met by burning whale oil, a luxury only available to the wealthy. Imagine our electricity needs in another 100 years. The market is evolving quickly and we are leaning more on technology and data to deliver electricity more flexibly and efficiently. Our customers are also asking for a better understanding of their electricity use and interactions with the network. In support of this we will develop:

- $11 million digital network program—we are responding to the transformation underway by building a smarter network that predicts and manages power flows on the low voltage network, ensuring we can run the network safely and more efficiently in the face of changing demands such as electric vehicles.
- $13 million SAP upgrade—our existing SAP program will be nearly 20 years old and unsupported by the vendor. Given the criticality of this program to the operation of our network, we will upgrade this product to ensure the continued functionality of our network programs and corporate functions.
- $9 million for five minute settlement—we will be required to provide five minute interval data for market settlement purposes, improving price efficiency in the generation market. System changes are required for us to collect and validate this data.

All our information and communications technology (**ICT**) investments are supported by business cases demonstrating the customer benefits from the programs and risk monetisation analysis where possible.

Property and fleet

Property and fleet investment is necessary to support the effective operation of the network for our customers. We will undetake:

- $79 million depot upgrade—upgrading five depots to deliver a resilient network
- $35 million security and compliance upgrade—to protect critical infrastructure in response to heightened risks.

We have undertaken a bottom-up approach to forecast our property requirements.

Operating expenditure

We already operate the most efficient network in the National Electricity Market (**NEM**). As a result, being part of the Powercor community means having among the lowest networks charges in Australia. It also means we have limited ability to absorb increases in operating costs. We are seeking a step up in our operating expenditure to manage new legislative and compliance requirements, which include:

- $15 million for new Australian Government obligations to move all customer and employee data related services onshore
- $22 million following the Country Fire Authority's classification of new high bushfire risk areas resulting in more pole inspections and vegetation management
- $5 million for higher bushfire insurance costs due to global insurance market conditions
- $10 million for new Environment Protection Authority regulations leading to more preventative environmental measures.

Our forecast operating investment is based on the AER's base-step-trend approach with 2019 being our representative 'base' year.

We are maintaining affordability by keeping our prices low

Revenue

We are proposing that real revenue decline in 2021 and thereafter remain constant. This will lower prices by $24 for our residential customers and $68 for small business customers. We will deliver this by:

- lowering our borrowing costs compared to the 2016–2020 regulatory period
- driving efficiencies through leaning on technology to make better decisions about our network
- finding ways to reduce costs in light of the AER's reduction to tax allowances.

Finding efficiencies

We have a strong track record of responding to the AER's incentives to reduce costs, but these are becoming increasingly difficult to find. Specific actions we undertook over 2016–2020 to deliver $326 million in savings to our customers included:

- re-tendering many of our outsourced services such as inspection and vegetation management
- where it was found efficient through market testing, we insourced functions such as some regional field operations and outsourced others such as information technology (**IT**) support and project delivery, and a number of design activities
- automating works scheduling and dispatch to improve the utilisation of our field resources and fleet
- reducing the size of corporate functions including finance, customer service, regulation and human resources
- re-considering our planned investment in a new billing system in light of new policy developments and acquiring the United Energy network (which means there is potential to migrate to its billing system).

The majority of these transformation programs are not repeatable, meaning we will need to consider more innovative and risky ICT solutions in the future. For 2021–2026, we have included a number of these more innovative ICT projects and reduced our investment requirements accordingly.

Metering

We will reduce our metering charges by around 13% and continue to ensure our customers benefit from smart meters through a number of services we already support. These include:

- faster restoration of faults—we receive immediate notification of outages which allows us to dispatch crews often prior to a customer even becoming aware of an outage.
- safer supply of electricity—we have developed an algorithm to identify potential loss of neutral at our customers' homes to prevent 'tingling taps' which pose an electric shock risk. Twice a day (and soon to be every 15 minutes) our algorithm checks all our customers' homes. In just under a year of operation, we have already detected and resolved over 1,600 deteriorated neutrals.

Over the 2021–2026 regulatory period, we will also implement better network load profiling, identification of safety risks and better enable more distributed energy resources on the network through the voltage data provided from these meters. These benefits ultimately deliver our customers lower network prices and better services.

We are supporting customers' energy choices through fair and simple charging

Our proposed changes to household tariff structures seek to accelerate the pace of reform without jeopardising the stakeholder support that is crucial to enable change.

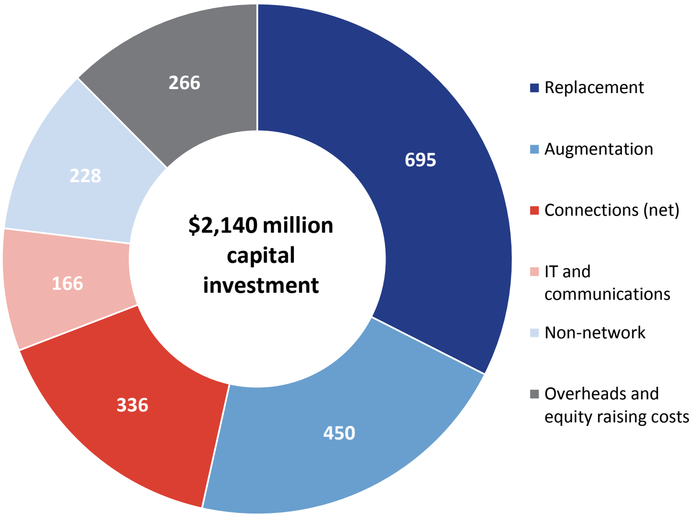
For residential customers, we will introduce a new two-rate tariff for new customer connections, customers seeking supply upgrades to three-phase and customers installing solar or batteries. The objective is to encourage customers to move discretionary electricity use into off-peak periods, when the network is under less pressure. Feedback from our customers strongly preferred the simplicity of a two-rate tariff.

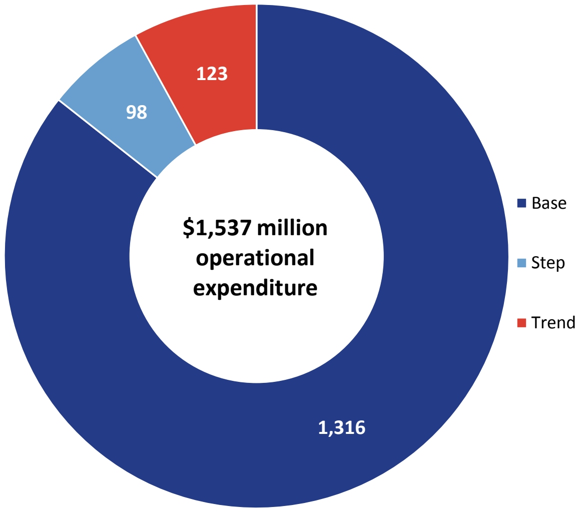
We will change the default tariff for small business customers from a single-rate tariff to a two-rate tariff. And for large business customers on demand tariffs we will change how demand is measured—from ratcheting demand to rolling demand.

Snapshot of our 2021–2026 forecasts

We have considered our forecasts in totality to ensure this proposal delivers the affordability outcomes our customers are seeking. To that end, we are keeping our total revenue flat compared to the 2016–2020 regulatory period, while providing more services. Our capital and operating forecasts are summarised below.

Summary figure 1: Capital and operating expenditure summaries for standard control services ($ million, 2021)





Source: Powercor
Notes: Includes real escalation. Augmentation expenditure is net of disposals, and the trend component of operating expenditure is net of our proactive productivity adjustment.

Our revenue building blocks are summarised below (modelled in nominal terms, consistent with the AER's revenue models).

Summary table 1: Revenue requirement for standard control services ($ million, nominal)

Building blocks	2021/22	2022/23	2023/24	2024/25	2025/26
Return on assets	218.9	231.6	242.4	248.1	251.1
Regulatory depreciation	131.6	142.2	155.6	159.5	171.0
Operating expenditure	314.8	310.4	327.4	341.0	358.5
Incentives	24.6	16.4	13.0	14.3	18.3
Corporate income tax	3.3	-	-	-	-
Unsmoothed revenue requirement	693.2	700.6	738.5	762.8	798.9
Revenue X factor (%)	**0.1**	-	-	-	-

Source: Powercor
Notes: A positive X factor means a real revenue decrease.

This regulatory proposal is supported by the business cases and attachments listed separately in appendix 10 (see attachment: PAL APP10).

We want customers to choose how they use electricity

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2 Stakeholder engagement

To enable our customers to use electricity in the way they want, we asked them about their preferences.

In today's rapidly changing energy market there has never been a more critical time for us to understand and respond to our customers' needs. We want to move beyond telling our customers what we're doing, to ensuring our proposal delivers what they want and need. This will allow us to anticipate and respond to our customers' changing preferences, support their energy choices, and provide better solutions.

We have been talking to our customers and key stakeholders about the development of our 2021–2026 regulatory proposal through our engagement program called 'Energised 2021–2026'.

Energised 2021–2026 started early, more than three years prior to submitting our regulatory proposal. We wanted to give customers plenty of time to engage with us, talk about their needs and review our plans. Starting early also allowed us to publish our draft proposal 11 months prior to submitting our regulatory proposal, in February 2019.

2.1 Our engagement objectives

Our core objective in designing Energised 2021–2026 has been to listen to our customers and stakeholders more than ever before.

To do this we created a program that reflects the International Association for Public Participation (**IAP2's**) inform, consult, involve and collaborate phases of engagement. We have strived to listen and educate, share alternative futures and investment options, support customer choices and provide better solutions.

Our objectives for engagement and integrating feedback into our proposal are outlined in table 2.1.

Table 2.1 Engagement objectives

Engagement	Awareness	Meaningful influence	Improve long-term outcomes
What we wanted to achieve	Achieve a level of awareness about our organisation, our role and the regulatory framework in which we operate.	Gather customer and stakeholder inputs and allow them to have meaningful influence on our proposal.	Actively involve customers and stakeholders in the process so we could understand changing views and preferences, and improve long-term outcomes.
What this meant for our five year plan	Deep insights into customer perspectives on everyday lifestyle changes implicated in different energy futures, both in terms of demand side and supply side changes.	Understanding of the key points of agreement and difference regarding considerations and trade-offs in developing our energy future.	Active involvement of customers and stakeholders to understand changing views and preferences and to improve long term outcomes.

Source: Powercor

2.2 Our journey with our customers during Energised 2021–2026

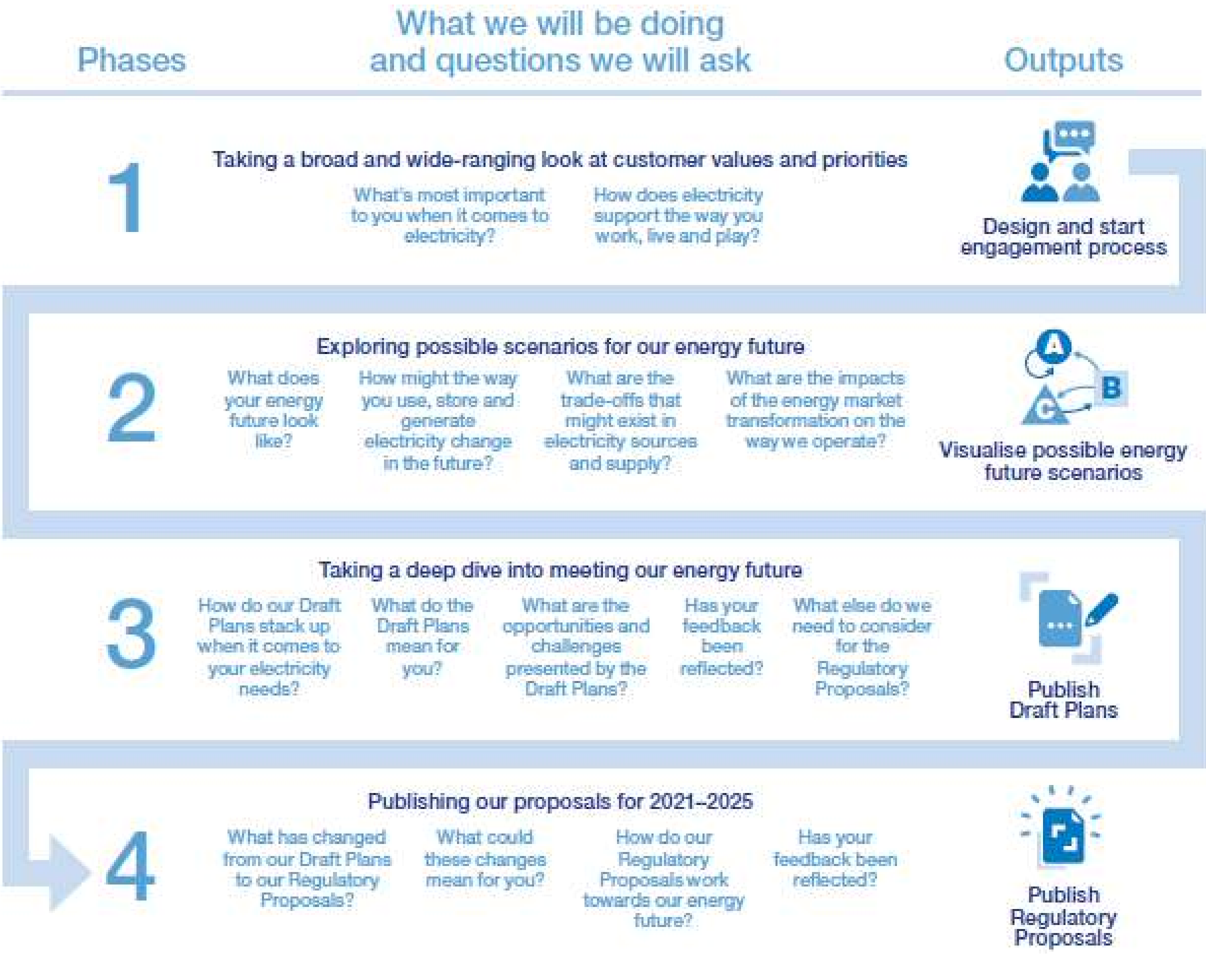
Energised 2021–2026 is designed to take our customers and stakeholders on a journey—sharing their energy values and preferences, deliberating with us on the network's current and future challenges and assessing real-life investment options and trade-offs.

Our approach is innovative—we have used deliberative democracy methods with forums and polling to involve our customers in deep knowledge building, and immerse them in our decision making processes. Our customers have evaluated real-world costs and benefits of new or revised approaches to service delivery and network management.

2.2.1 Engagement phases

There were four key phases that guided the design and delivery of the customer and stakeholder engagement as shown in figure 2.1.

Figure 2.1 Engagement process



Source: Powercor

In the 11 months since we published our draft proposal, we have continued to engage on issues, particularly a number of marquee projects such as solar enablement, upgrading regional supply, digital network and customer enablement. The projects (and more) are discussed in our proposal.

2.3 Our engagement activities and reach

We undertook a range of engagement activities as part of Energised 2021–2026 and reached out to a large number of our customers. These are summarised in table 2.2.

Table 2.2 Summary of engagement activities

Activities	Purpose of engagement	Metrics
Talking Electricity website	Provide a centralised online hub for important information, updates and news about our progress	20,844 page visits
Newsletters	Provide updates on our progress throughout the process	489 subscribers
Pop-up displays	Provide information, subscribe new customers and seek insights about energy usage	Pop up displays in Geelong Westfield's with 166,192 reported foot traffic
Focus groups	Collect exploratory insights on values, customer priorities for the future, renewables, electricity bills and customer impacts	South Melbourne and Richmond
Interviews	Discuss energy futures, impacts to business, connections, tariffs, energy sources and future investment plans around energy	25 interviews
Surveys	Understand values and preferences on key issues Understand scope, limits and level of support for some of our flagship programs in the proposal	2,709 surveys with residents and businesses with access to insights from 7,793 surveys across all our networks
Meetings	Detailed discussion about our proposal	714 meetings with 2,353 interactions
Workshops	Discuss and decide on the approach to topics like pricing, data, renewables and connections	579 participants over 30 forums or workshops
Citizen led deliberative forums	Provide forums for the public to hear from experts about energy futures and provide feedback on their values, the trade-offs, customer impacts and priorities	266 participants during 4 deliberative forums
Future networks forums	Co-design energy futures to test with customers and ensure we prepared possible and plausible options for discussion Discuss options to enable solar exports, demand response programs and incentives to encourage customers to shift their energy load	78 participants in two joint network forums
Advisory panel	Facilitated detailed discussion about all elements of the proposal including approach, modelling, insights, market trends, regulation, pricing, connections, community safety, renewables, customer impacts, performance, the draft proposal and our proposal	1,120 interactions with customer reference panel members 18 panel meetings with our customer reference members
Draft proposals and engagement reports	Cover the insights we've collected along the process, how feedback has been considered and how we'll work towards the proposed energy future	Draft proposal published and viewed 1,250 times
Podcast	Inform customer about the proposal purpose and what it includes	319 podcast listens across our networks
Open House	Ensure opportunity for local government and other community opinion leaders to learn more about the draft proposals and give input	26 community opinion leaders and local government representatives

Source: Powercor

To help customers engage with us, we also developed a new tool to compare elements of the regulatory proposal and their impact on the average bill. This provided us with insight into customer preferences and priorities in the context of a trade-off between different services and affordability.

2.3.1 A wide range of views

To ensure our engagement process was inclusive, we listened to a range of voices, including the hard-to-reach and not just the 'usual suspects', such as:

- we travelled to regional areas to speak to regional community leaders to understand their specific issues
- culturally and linguistically diverse, and vulnerable customer groups through a range of bespoke engagements
- small and medium business enterprises participated in surveys and deliberative workshops with our residential customers
- targeted interviews with our commercial and industrial customers.

We also recognised the need for a dedicated advisory panel capable of representing the perspective of our customers. Therefore, we established the Energy Futures Customer Advisory Panel (**EFCAP**) in 2017, which consisted of 11 members with a diverse representation of customers and stakeholders. The EFCAP met every three to four months to consider concepts, projects, issues and challenges relating to the development of our proposals.

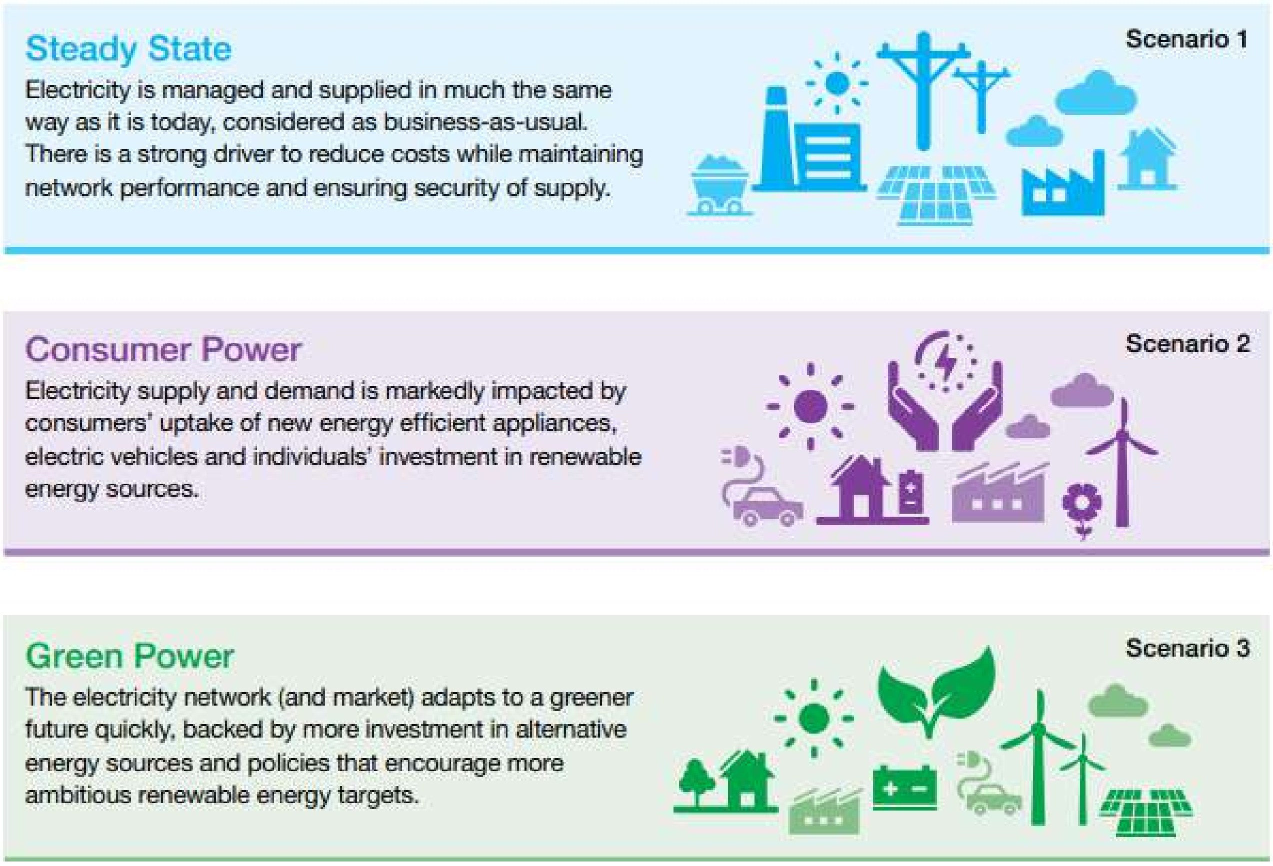
We have also discussed our proposal with our longstanding Customer Consultative Committee (**CCC**), established over 10 years ago to provide an independent voice in our decision making process, and invited members of the AER's Consumer Challenge Panel (**CCP**) to independently review our engagement approach and provide guidance.

2.4 What we heard

2.4.1 Our customers told us their preferred energy future

A core component and the starting point of Energised 2021–2026 was establishing a shared energy future that meets the needs of our customers and the communities they live in. To understand how our customers and stakeholders see their energy future, we co-designed three potential energy future scenarios with our customers, consumer advocates and stakeholders and asked them which would best support their lifestyles in the future (shown in figure 2.2).

Figure 2.2 Three energy futures scenarios co-developed with our customers and stakeholders



Source: Powercor

Ultimately, stakeholders acknowledged Steady State as the immediate priority to reduce costs while maintaining network performance and security of supply. Over time however, increasing consumer power and interest in environmental factors were considered likely to lead to greater investment in alternative energy sources and policies that encourage more ambitious renewable energy targets.

Our proposal reflects feedback by adopting the Steady State scenario while also reflecting the Victorian Government's renewables targets, including policy changes such as Solar Homes, in the most affordable way for our customers. We have also adopted key elements of the Consumer Power scenario by offering more solutions to customers who want to better access their data and use technology to more actively participate in the electricity market.

2.4.2 A safe and dependable, flexible and affordable network

We asked customers about what matters most to them and we heard three common themes in all our feedback, which are summarised in figure 2.3.

Figure 2.3 What we heard from our research in Energised 2021–2026

Source: Powercor

Resilient network

Our customers view having a reliable and safe supply as a single key concept; a resilient network. For example:

- customers are not willing to trade off current reliability for cost savings, however, they are willing to pay to improve reliability in areas with poorer service
- safety is seen as a given, and most trust that we are making the right decisions in this area—customers want safety to be maintained and improved where possible across the network but balanced with costs
- residents and small and medium businesses are satisfied with reliability and power quality levels and want them maintained, whereas commercial and industrial customers would like power quality improved
- there is support for safety initiatives to reduce the risk of bushfires (such as using new technology, undergrounding and optimal pole inspections), however, in south-western Victoria there were questions as to whether the current proposals are 'enough' to ensure a safe network that mitigates bushfire risk.

Affordable network

Affordability permeates every discussion we have about electricity. Participants shared the following:

- affordability is highly valued and many see current electricity prices as too expensive
- customers are interested in receiving rewards and incentives for participating in demand management, and some commercial and industrial customers would like further dialogue with us about options.

Flexible network

Flexibility revolves around choice and enablement. It means giving customers options to participate with the energy market in a way that suits them most. Our customers:

- have a vision for a greener future, and they expect an increase in the use of renewables (solar and batteries)—both large and small scale
- want the network to facilitate and cater for this increased renewable uptake, ensuring consistent quality of supply for all customers and enabling solar export
- would like to see us being proactive rather than reactive and implementing plans for an increase in renewables now
- liked the idea of access to real-time energy usage data but most were not willing to pay more for this
- raised concern around data security and were not supportive of remote control of their appliances.

2.5 How this has shaped our proposal

Our customers are at the centre of our 2021–2026 regulatory proposal. Their feedback and how it was used are highlighted and demonstrated throughout our regulatory proposal where most relevant. We summarise how we have incorporated key insights of our customers' wants and needs into our proposal in table 2.3.

Table 2.3 Summary of how feedback has shaped our proposal

Phases and approach	Outcomes	Our response
Phase 1: explore customer values and priorities • Surveys • Focus groups • Interviews • Online tools	Our customers needed to learn more about who we are and what we do. Our customers won't trade off reliability for cost savings. Around two-thirds of residential customers perceived their electricity bills as too high. Customers and stakeholders want to see the power put back into people's hands, with access to real-time data and a customer-centric focus.	• Strengthened our communications to build awareness and a level of trust—eNews, Talking Electricity, advertising and podcast • Maintaining our position as the most reliable rural network in Australia with supply available for over 99.97% of the year • Ensuring we maintain our position as the most efficient network • Committed to deliver a customer service strategy and improve customer-facing applications for outages, faults and consumption data.
Phase 2: explore scenarios for our energy future • EFCAP • CCC • Citizen-led deliberative forums • Workshops, surveys and meetings	Customers have a vision for a greener future, and 75% of them thought the network should be upgraded faster than is planned, to allow for renewable energy. The preferred energy future was a steady and progressive integration of renewable energy with a measured reduction in tariffs, by 2026, and improved power quality (fewer power fluctuations).	• Began developing a vision for our network that reflects our customers and stakeholders' expectations, including a progressive integration of renewables • Identified future technologies at the network and community level that are likely to be integrated onto the network • Identified how customer choices can be improved, including through enabling their access to more useful data • Developed pricing principles to guide our decision making for tariffs.
Phase 3: sense checking our draft proposal • EFCAP • CCC • Second round of citizen-led deliberative forums to assess investment options • Deep-dives with stakeholders • Workshops, surveys and meetings	Customers agreed to their values for electricity: • providing a reliable supply of electricity • maintaining affordability • committing to providing a safe environment for customers and workers • using electricity when you want or receive savings for reducing use • committing to providing a safe network that mitigates bushfire risks • keeping your data and our network secure • making it easier for you to export solar and charge your battery • making it easier for you to connect • making it easier for you to use your data to make informed choices.	• Combined reliability and safety into resilience to demonstrate their interrelatedness • Reviewed and updated our pole-inspection policy in response to community concerns • Committed to network price reductions • Commenced consultation on time-of-use pricing • Developed a vulnerable-customer campaign to improve energy and bill literacy • Developed initiatives to increase the network's ability to accommodate renewables and customer-driven technologies • Developed initiatives to deliver customer benefits through improved digitalisation and visibility of the low voltage network • Developed initiatives to better enable customers to have easier access to their data and to make more informed choices • Tested options for addressing customers' needs, including presenting bill impact of each option

Phase 4: preparing our proposal • Release of the draft proposal • EFCAP • CCC • Third round of citizen-led deliberative forums on the draft proposal • Deep-dives with stakeholders • Workshops, surveys, meetings • Open-house • Community displays • Podcasts	Draft proposals were generally supported, particularly: • undergrounding of infrastructure in bushfire areas ending 2030 • increasing pole inspections, especially in the South West region • no customers experience outages when it comes to REFCLs • exporting for solar customers • improving reliability in worst-served areas • investing in regional communities • investing in new technology to improve reliability and safety, and encourage renewable generation • providing access to data that tells people how much energy they use at different times of the day and how much each of their appliances cost to run • multi-modal communications about outages, faults, programs and our services.	• Finalised our network vision reflecting customers' expectations, including a progressive integration of renewables and maintaining/improving services at least-cost • Amended our pole replacement program with ESV, to address community concerns around the long-term sustainability of our poles • Understood the regional community challenges and co-designed a business case, with support from our wider customer base • Redesigned our solar approach and finalised the business case through extensive consultation with a wide variety of key stakeholders on options analysis and analysing customer benefit streams • Strategically aligned solutions to mandated REFCL installation and future growth areas • Finalised the business case for improved digitalisation and visibility of the LV network, ensuring we continue to deliver a reliable, least-cost network through deferred augmentation • Finalised our business case for customer enablement using extensive feedback on customer preferences for access to their data • Finalised our proposal for time-of-use pricing with a slower transition path to ensure all customers are supported through tariff reform.

Source: Powercor

More information is available in our stakeholder engagement appendix.[1]

[1] PAL APP01: Powercor, *Stakeholder Engagement*, January 2020.

3 Our energy future

Our customers are looking to more actively participate in their energy future. They are generating, storing and exporting more electricity back into the network, marking one of the most significant transformations to the electricity industry of recent times. They also want to become more involved in new demand response programs, search more actively for the best energy prices, and expect their electricity requirements will change as electric vehicles (**EV**) become commonplace. New market developments will support customers as they engage in peer-to-peer trading. At the same time, they still expect us to prioritise safety and affordability.

3.1 We are preparing for a shared energy future today

The changes customers are seeking will create more efficient markets and allow them to share in the gains, but will also make network management more complicated. As a result, we are investing to deliver customers the network they need.

We are excited to plan for this shared energy future with our customers. The world does not stand still, and neither are we. Our initiatives to unlock new value are summarised in figure 3.1.

Figure 3.1 Our initiatives are helping to unlock new value for customers now and in the future

Customer outcomes	Ensure safety and reliability	Lower costs through efficient network management	Enable more solar exports	Support prosumers
Example initiatives				
Emerging	• Asset condition monitoring	• EV charging optimisation • Electricity theft detection	• Network optimisation (e.g. transformer tapping) • Phase rebalancing	• Peer-to-peer trading • Solar health notifications • Streamlined customer portals
Developing	• LV asset failure prediction	• Demand response programs	• Dynamic voltage management	• Community energy projects
Existing	• Remote reconnection • Neutral fault detection • Streamlined connection requests	• Remote meter reading • New wood scan practices • Vegetation management using LiDAR	• Voltage and load management	• Energy usage dashboards
Enablers	AMI, new technology, government policies, industry partnerships, engaged consumers			

Source: Powercor

3.1.1 Building strong foundations for our energy future through smart meters

We are already preparing for our shared energy future by making the most of our smart meter data. We have full penetration of smart meters across our residential and small business customers, which puts us in a unique position compared to distributors in the rest of the world.

Over 97% of our customers support using smart meters to better manage the network. We currently do this, for example, by:

- streamlining the connections process and lowering bills by allowing for remote connections and meter readings
- improving safety by identifying neutral faults at customer premises
- enhancing supply through more automated detection and dispatch, and rotated load shedding on peak demand days (if required).

Continuing to build the capabilities and experience to operate the network dynamically means we can enhance these existing services, and offer more value to customers in the future. Over the 2021–2026 regulatory period we will build the capabilities to operate the network more efficiently and in real-time to promote the uptake of new technology, optimise load control of customer appliances and enhance the cost reflectivity of pricing. Through managing the network more efficiently, we will lower network costs and put downward pressure on customers' electricity bills.

3.1.2 Supporting the uptake of new technologies

We have some of the highest uptake of rooftop solar in the world as longstanding blockers to solar uptake are removed by technological innovation, declining costs of renewable generation and battery storage, and improvements in the way distributed energy resources (**DER**) are reliably integrated into the network.[2] Customers and governments are increasingly driving this uptake to receive more reliable, affordable and cleaner energy—more than half of residents and businesses are interested in solar export and 59% of residents believe the network should be upgraded more quickly to allow for more renewable energy connections and exports.

Growth in solar uptake is also being supported by government policies. The Victorian Government recently committed $1.2 billion to support the installation of solar panels on 650,000 Victorian households over 10 years.[3] It has also committed to a $40 million program to provide half-price solar batteries for 10,000 Victorian households to encourage uptake and micro-grid development.[4]

However, the higher network voltages caused by solar means that if we do nothing, customers' solar will be automatically constrained by their inverters and they will lose the benefit of solar. We have used advanced analytics and our smart meter data to determine the most efficient way to remove solar constraints in an affordable way so that most customers can export with a 5kVA system. Over the 2021–2026 regulatory period this project will allow us to unlock over 95% of the solar that would otherwise be constrained while maintaining affordability.

This benefits all customers through replacing higher cost generation which places downward pressure on electricity bills for all our customers, regardless of whether they have their own solar panels.

3.1.3 Engaging in demand response

We are increasingly offering incentives to our customers to decrease energy usage during peak events to address network constraints and help manage assets. Almost two-thirds of our customers said they are interested in participating in demand response programs.

An overview of the exciting new steps we are taking in this space, such as our behavioural and controlled load demand response programs, are outlined in table 3.1.

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2 PAL ATT171: Marlene Motyka, Andrew Slaughter and Carolyn Amon, *Global renewable energy trends: Solar and wind move from mainstream to preferred*, September 2018.

3 PAL ATT173: Office of the Premier, *Cutting Power Bills With Solar Panels For 650,000 Homes*, August 2018.

4 PAL ATT174: Department of Premier and Cabinet (Vic), *Victorian Infrastructure Plan*, October 2017.

4 PAL ATT172: Office of the Premier, *Cheaper Electricity With Solar Batteries For 10,000 Homes*, September 2018.

Table 3.1 Current period demand response programs

Program name	Solution	Capacity	Target audience
Energy Partner (demand response trial)	Behavioural demand response program in partnership with the Royal Automotive Club of Victoria (**RACV**) to reduce energy at risk on the Surf Coast and Bellarine Peninsula. Sensibo thermostat devices provide controlled load with customers compensated $20 per event.	0.5–1MW	Surf Coast Shire Bellarine Peninsula Residential customers
Voltage management	Voltage management at zone substation level to reduce network demand during peak periods. Vulnerable load and life support customers are closely monitored or excluded through events	60MW	Network wide
Commercial customer load control	We are exploring partnerships with commercial customers to reduce network constraints by reducing demand	2MW	Large electricity users with sophisticated energy management strategies

Source: Powercor

To maximise the savings these programs can deliver, we are investing in understanding our customers better through various partnerships including:

- RACV channel partnership to test and learn from different brand associations and marketing channels
- CitySmart and Queensland University of Technology research project linking load profile analysis to customer archetypes to refine customer value propositions and messaging for demand response programs
- Renewable Newstead which involves designing an innovative community network tariff
- microgrid project where we have been in discussions with the AER about supporting microgrid establishment
- solar and battery storage facility where we negotiated a unique connection agreement with providers, which can be leveraged for future solar and battery storage facilities.

3.1.4 Supporting our more vulnerable customers

We need to ensure that as our energy system evolves, no one is left behind.

We are exploring opportunities for outreach to residential customers who are economically vulnerable. This includes launching a flagship program in conjunction with the Australian Energy Foundation (**AEF**) to work with the Western Bulldogs Community Foundation.

We have been exploring ways to support opportunities for outreach to residential customers who are economically vulnerable in our service areas. As part of this, we engaged with AEF to assist us in working with the Western Bulldogs Community Foundation to support the education and upskilling of economically vulnerable customers. This includes leveraging the Western Bulldogs Community Fund Partnership to create programs and associated tools and materials to help these customers get the best tariffs, make the most of available concessions and grants available, and provide information on how to manage electricity consumption in their home.

In 2019, we delivered an energy literacy program to the foundation's mental health support groups, Daughters of the West and Sons of the West, and the Ready, Settle, Go programs for recent refugees and migrants. More than 4,500 people have participated in these programs.

Ultimately, the program will improve energy management outcomes, reduce energy costs, increase people's confidence dealing with energy and develop a group of leaders within the community so that this knowledge is passed on and utilised into the future.

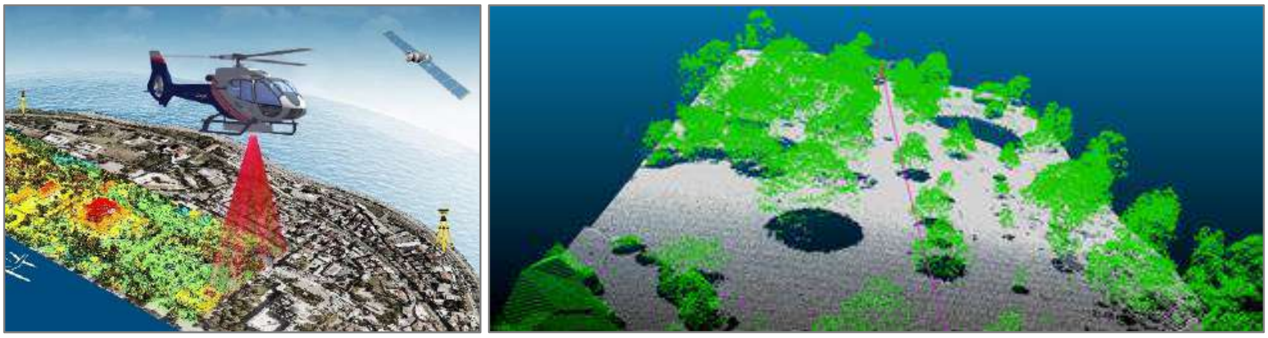
3.1.5 Managing assets in smarter ways

To keep up with changes in our network and our environment, we continuously seek out the best in asset management practices. This includes harnessing the opportunities that technology provides and collaborating with industry partners.

For example, we embarked on a partnership with Swinburne University to find new ways of assessing the health of lower-condition poles through less invasive and more effective inspection methods. This allows us to extend the life of our assets and pass on lower costs to customers, all while still ensuring the safety of our employees and the community.

We have also implemented light detection and ranging (**LiDAR**) to make digital representations of vegetation growth across our entire network. This is done through emitting a laser light and measuring the reflected light pulses. We use this visualisation, in addition to analytics algorithms, to determine where vegetation cutting is required.

Figure 3.2 Example of LiDAR data visualisation to identify vegetation growth



Source: Google images and Powercor

3.1.6 Empowering more informed customers

Technological development in how organisations capture and display data across a number of industries, including health and finance, means customers can access more information about products and services. Through sharing energy data with our customers, we are helping them to take control of their energy usage.

Our 'myEnergy' dashboard allows business and residential customers to gain visibility about their energy use, see how this compares to their neighbourhood average, and use this data in the Victorian Energy Compare website to get the best energy deal—our customers see a one-stop-shop as simplifying their lives and providing them with information to make better decisions. Our myEnergy dashboard also allows customers with solar to see how much they are exporting back onto our network.

We will continue to engage with customers and learn more about how they want to engage with us by:

- implementing consumer segmentation research to improve engagement and drive better network outcomes
- understanding customer motivations and drivers to ensure programs target their needs and expectations
- working with network planners to ensure we target the right customers in those areas of most need
- identifying partners that can help us provide meaningful value to customers and the network.

Every day we supply electricity to power our customers' activities

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4 Replacement

Summary

We take great pride in the role we play in providing an essential service for our communities—a safe and dependable supply of electricity is critical each and every day. We are Australia's most reliable rural network, and since 2012/2013, we have reduced the number of ground fire starts from our assets by 25%, and driven a 35% reduction in public safety incidents.

Our replacement investment in the 2021–2026 regulatory period to provide a safe and dependable supply of electricity has been informed by insights from our ongoing stakeholder engagement program:[5]

- we are responding to concerns raised by our communities about the long-term sustainability of our pole replacement volumes by proposing enhancements to our risk-based approach to managing our wood pole population (an outcome of which is that we will intervene on more poles).
- we are leveraging our smart meter network to minimise safety risks as far as practicable. This includes using analytics to proactively detect hazardous assets. The use of smart meter data allows us to make decisions that prolong the useful life of components of our network, without compromising reliability of supply or network safety.
- we will continue to effectively reduce the risk of bushfires from our network by replacing assets in high bushfire risk areas. Our bushfire mitigation program is reflected in our bushfire mitigation plan, which is approved by Energy Safe Victoria. Our customers hold strong views that safety should always be a top priority.
- we are working with specialist vendors to develop 'smarter' switches that will allow us to address the detrimental reliability impacts being experienced by customers in areas where rapid earth fault current limiters (**REFCLs**) have been commissioned.
- we have commenced a program to progressively replace switches on our network that have required restricted operational practices. This program will reduce the minutes off supply our customers experience due to planned outages.

Our asset management decisions are also increasingly relying on new research and innovation. This helps us make efficient, data-driven decisions to replace our poles, wires and major electrical plant inside our zone substations. For example, we are using new technologies to inspect our assets with non-destructive methods (such as WoodScan for poles) that support the integrity of the existing asset during the inspection process, and are expected to provide more accurate information on asset condition.

Similarly, our current partnerships with a number of universities across Australia are identifying better ways to manage our assets, including:

- supporting catastrophic bushfire consequence modelling with CSIRO to provide quantitative fire risk analysis
- investigating alternative materials to cover overhead lines and prevent fire starts, and undertaking termite treatment trials to identify more effective wood pole treatment alternatives
- we are working with research partners to develop algorithms that identify vegetation clearance breaches from our state-of-the-art light detection and ranging (**LiDAR**) survey of lines so we can improve safety outcomes.

In addition to leveraging our smart meter network, innovation was something our customers said they expected from us during our stakeholder engagement process.

Affordability was a common theme from our customers as well. To ensure our regulatory proposal includes efficient replacement investment, we carefully quantify and assess risks to our customers (including safety, reliability, financial, bushfire and environmental impacts). We only invest in replacing assets when the probability-weighted cost of these risks exceeds the value of the least-cost intervention.

In total, over half our forecast investments are supported by risk monetisation models and/or business cases, including all major zone substation asset replacements. Our approach to quantifying risks is consistent with the AER's replacement planning practice note.[6]

As discussed in this chapter, after accounting for new policy and regulatory compliance obligations (which are not reflected in our historical expenditure), our total replacement investment is supported by the assessment approach applied by the AER in its recent decisions for other electricity distributors.

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5 As set out in the stakeholder engagement chapter of this regulatory proposal, our engagement program included a series of deliberative forums and customer surveys. These insights were presented in our draft proposal, and discussed during our risk management deep-dive.

6 PAL ATT099: Australian Energy Regulator, *Industry practice application note: asset replacement planning*, January 2019.

This chapter outlines our investment in the 2021–2026 regulatory period to replace existing assets:

- in section 4.1, we outline the services our forecast investment will allow us to deliver
- in section 4.2, we provide further detail on our approach to developing our investment forecast, including our asset management practices and risk monetisation process.

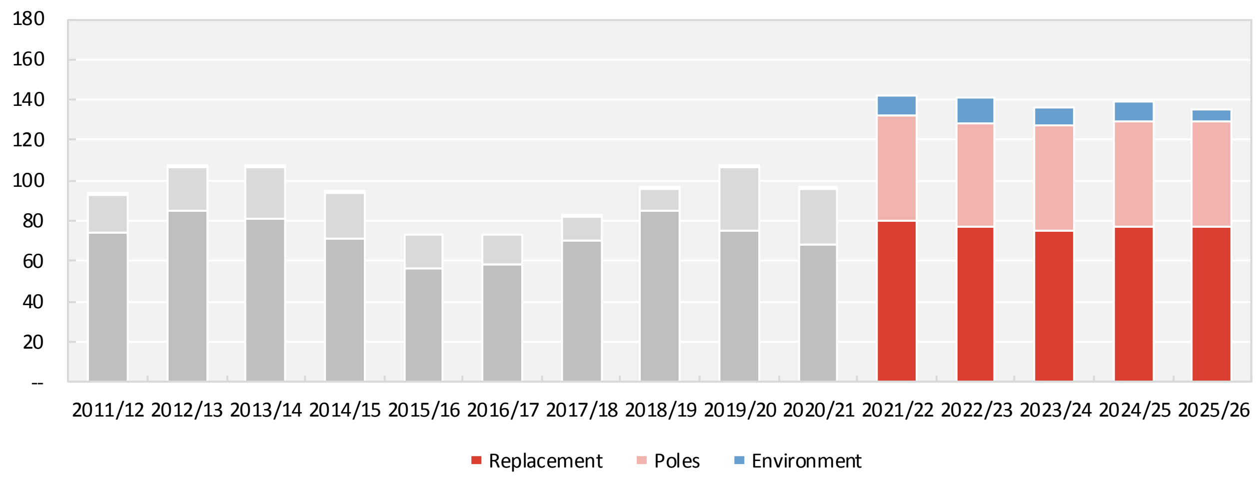
The replacement of existing assets occurs as the condition of our network infrastructure deteriorates over time, and investment is required to continue to meet our network safety, reliability, bushfire mitigation and environmental obligations. This is consistent with the capital expenditure objectives, criteria and factors set out in the National Electricity Rules (**the Rules**). Table 4.1 and figure 4.1 provide an overview of this investment over previous and future regulatory periods.

Table 4.1 Total replacement investment ($ million, 2021)

Description	2016–2020	2021–2026
Replacement total	455.4	694.8

Source: Powercor
Notes: Forecast shown includes real escalation.

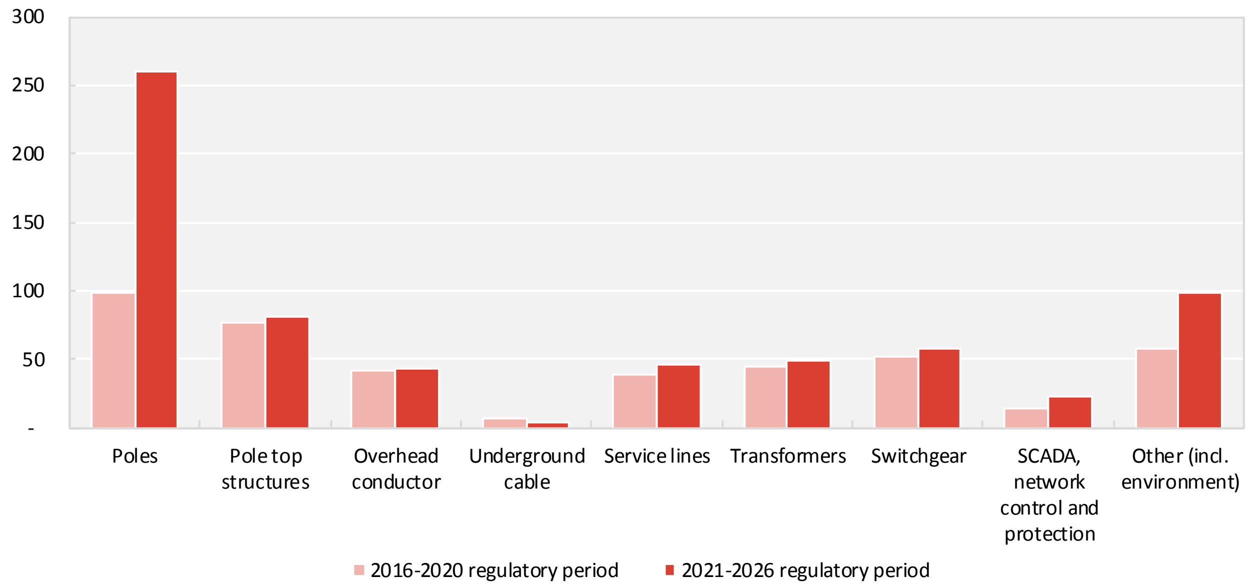
Figure 4.1 Forecast investment to replace existing assets ($ million, 2021)



Source: Powercor
Notes: Forecast shown includes real escalation.

Our forecast investment for replacing existing assets is increasing relative to our historical investment program, primarily due to the inclusion of additional pole replacements and new environmental compliance obligations. Our forecast has also increased from our draft proposal for the same reason. A comparison between our historical and forecast regulatory periods, at the asset category level, is shown in figure 4.2.

Figure 4.2 Historical and forecast replacement investment by RIN category ($ million, 2021)



Source: Powercor
Notes: Forecast shown excludes real escalation.

The justification for our forecasts is provided in series of business cases and risk models for our key projects and programs. These are summarised in table 4.2, and cover over 47% of our total replacement investment.

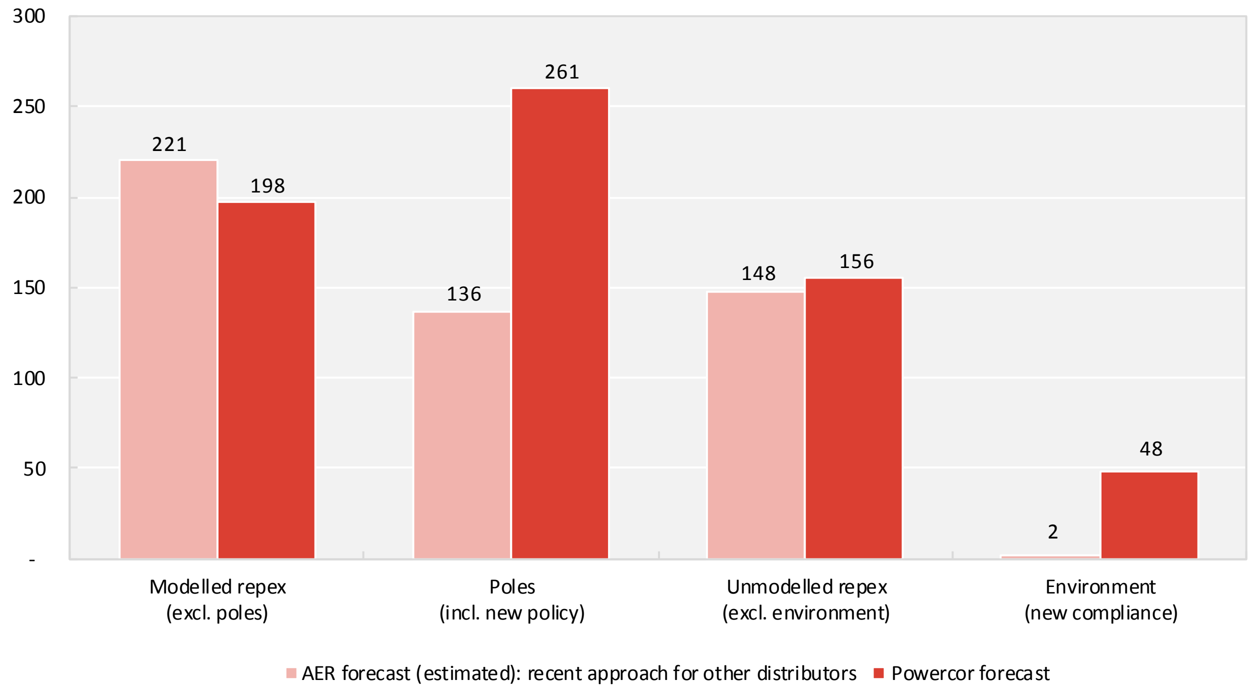
Table 4.2 Summary of material business cases: total forecast investment, 2021–2026 ($ million, 2021)

Description	Investment
Wood pole replacement program (excluding fault response)	233.8
Environmental management program	47.8
Mitigating REFCL reliability impacts	13.0
Transformer replacement: Robinvale no.1	1.5
Transformer replacement: Robinvale no.2	3.9
Transformer replacement: Warrnambool no.3	3.5
Transformer replacement: Inglewood regulator	1.3
HV air-break switches: CRO tagged interrupter replacements	6.9
Total business case	**311.6**

Source: Powercor
Notes: Forecast shown excludes real escalation.

After accounting for new policy and regulatory compliance obligations (which are not reflected in our historical expenditure), our forecast compares favourably to estimates based on the AER's recent assessment approach for other electricity distributors. For example, the first pair of columns in figure 4.3 shows that our forecast is lower than our estimate of the AER's repex model (excluding poles). Our estimate of the AER's repex model is discussed in further detail in section 4.2.5.[7]

Figure 4.3 Comparison of AER's recent approach to other distributors against our regulatory proposal ($ million, 2021)



Source: Powercor
Notes: Forecast shown excludes real escalation.

4.1 What we plan to deliver

To ensure we continue to supply the households and businesses within our communities with the electricity required to power their activities, we commit to providing the following over the 2021–2026 regulatory period:

- safe environment for our customers and workers
- safe network that mitigates bushfire risks
- reliable supply of electricity.

4.1.1 Providing a safe environment for our customers and workers

The safety of our communities, and that of our workers, is our first priority—we never compromise on safety. That's why our workers are extremely well trained and our asset management practices are based on international standards.

Some network assets, however, can fail without warning and may pose a safety threat. We undertake a range of activities as part of our asset management practices to reduce the likelihood and impact of asset failures. For

[7] For completeness, expenditure typically treated by the AER as 'unmodelled' is also shown, excluding our environmental investment which is driven by new compliance obligations.

example, we undertake proactive, safety-driven replacement programs when we identify deficiencies in families of assets, or when new technology enables us to better mitigate risks. This is consistent with our regulatory obligations to design, construct, operate, maintain and decommission our network to minimise as far as practicable (**AFAP**) the hazards and risks to the safety of any person arising from the network.[8]

Our forecast replacement investment for the 2021–2026 regulatory period includes our ongoing and proactive safety-driven programs. These programs, which also support the reliable supply of electricity, are discussed below.

Pole replacement program

Poles are essential to an overhead electricity distribution network. Their basic function is to support overhead electrical conductors and other pole mounted assets, and to provide safe clearance from the ground and other adjacent objects (including vegetation).

Our electricity network comprises over 577,000 poles, mostly constructed of wood. We currently inspect around 185,000 of our poles each year, in accordance with our legislated inspection requirements.[9] Our inspection practices include the use of innovative technologies, such as Woodscan, to improve the accuracy of our asset intervention decisions.[10]

Our pole asset management practices have resulted in relatively low wood pole failure rates. For example, we have historically experienced around four wood pole failures per 100,000 poles on our network.

Notwithstanding our low historical wood pole failure rates, we recognise that concerns regarding pole safety have been raised following the St Patricks Day fires in March 2018. These concerns, and the feedback received, are summarised below.

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8 *Electricity Safety Act* 1998 (Vic), section 98.

9 *Electricity Safety (Bushfire Mitigation) Regulations* 2013 (Vic).

10 Woodscan is an ultrasonic scanner measuring pulses travelling between 12 contact points around the pole to detect if there are any defects inside the pole.

Stakeholder feedback

It is clear our communities have become increasingly concerned at the sustainability of our pole replacement program. These concerns have been supported by strong engagement from both state and federal ministers.

With the assistance of Woolcott Research and Engagement, we convened a special topic roundtable in Warrnambool in March 2019 to discuss pole inspection and replacement practices. Participants were asked about the cost consequences of proposed asset management changes, which included a material increase in forecast investment relative to historical expenditure.

Most participants were supportive of our proposed actions. A prevailing view was that plans should not be about the number of poles to be replaced, but rather, about how safe the poles actually are:

> *'They have got to be able to be replaced when needed – there might be more than 4,000 additional a year and then they will all need to be replaced at once because they were put in over a short time.'*
>
> *'It should be about safety not economics.'*
>
> *'What we really want is confidence in the infrastructure. People need to feel that it is safe. It is all about perceptions not numbers.'*
>
> *'It should be about more than just the economic value of replacing poles.'*

Following our roundtable, a bushfire safety forum in Terang was attended by the Federal Energy Minister, Angus Taylor, and the Federal cabinet minister and Member for Wannon, Dan Tehan, alongside state politicians Richard Riordan and Bev McArthur. The forum was attended by 60 members of the community. The key message from the Energy Minister was that our current inspection and replacement program needed to improve.

In order to provide our communities with greater assurance regarding the safety of our network, we amended our pole replacement practices in 2019. These amendments are consistent with our AFAP obligations, and included increasing the amount of 'sound wood' required for poles to remain in service. The changes were accepted by ESV in our bushfire mitigation plan (**BMP**).[11] This followed a review by ESV of the condition of our poles in the south-west of Victoria.[12]

In the second half of 2019, ESV undertook a further review of the longer-term sustainability of our wood pole replacement program. This involved a comprehensive end-to-end review of our wood pole asset management life cycle process.

A draft report for ESV's sustainability review was published in December 2019. ESV made a number of recommendations, with three clear conclusions:[13]

1. The wood pole management system in place in March 2018, at the time of The Sisters fire at Garvoc, would not deliver sustainable safety outcomes for the future.
2. Since March 2018, Powercor has improved its wood pole management system, which has the effect of increasing the volume of wood pole replacements and reinforcements. However, these changes alone will not deliver sustainable wood pole safety outcomes for the future.
3. Powercor is progressing further improvements to its wood pole management system based on a more comprehensive risk assessment and better inspection practices that, when implemented, will as far as practicable, deliver sustainable safety outcomes to the community.

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11 PAL ATT094: Powercor, *Bushfire Mitigation Plan 2019–2024*, December 2019.

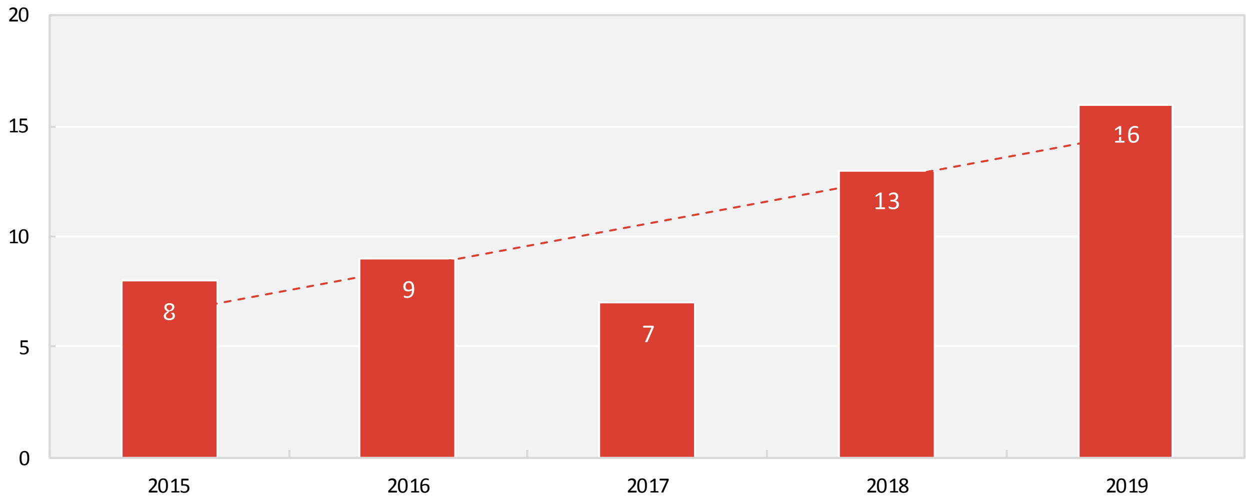
12 PAL ATT133: Energy Safe Victoria, *The condition of power poles in South West Victoria*, July 2019.

13 PAL ATT176: Energy Safe Victoria, *Draft report: Powercor wood pole management, An assessment of sustainable wood pole safety outcomes, Public technical report*, December 2019, p. 25.

The draft conclusions from ESV's sustainability review reinforce the findings from our own internal reliability centred maintenance (**RCM**) review conducted in 2019. Our RCM review highlighted the following concerns with the performance of our pole asset class that support the need to change:

- the historical trend in pole failures is increasing (as shown in figure 4.4), whereas the number of poles classified as 'unserviceable' has declined
- a higher than expected number of poles are transitioning directly from a serviceable to unserviceable state between inspection cycles.

Figure 4.4 Historical wood pole failure performance (number)



Source: Powercor
Note: Data represents our historical wood pole failures over time with the impact of weather events removed.

In response to ESV's findings, and our RCM review, we are implementing a risk-based asset management program. We have also changed our pole serviceability assumptions regarding the fibre-strength of wood poles. Specifically, our existing replacement criteria assumes the fibre-strength of a wood pole is the same in year one as it would be in year 100. We have amended this assumption to capture a more robust expectation of age-based degradation.

Our risk-based asset management approach aligns with the conceptual framework set out in the AER's recent asset replacement guidance practice note.[14] For example, we use our existing condition information and revised serviceability criteria as a proxy for the probability of asset failure. Our consequence of failure assumptions reflect a mapping of pole location to our defined bushfire risk zones.

The changes in our pole management practices will result in a significant step up in our wood pole replacement and reinforcement volumes. These volumes include compliance driven interventions (i.e. where a pole is assessed as unserviceable, we are required under our safety obligations to intervene) and risk-based

[14] PAL ATT099: Australian Energy Regulator, *Industry practice application note: asset replacement planning*, January 2019.

interventions. Our intervention response, however, depends on the particular circumstances and risk, rather than being deterministic.[15]

A summary of our forecast wood pole intervention volumes, as well as the required investment in the 2021–2026 regulatory period (excluding fault response) is shown in table 4.3.

Table 4.3 Wood pole replacement volumes and investment, excluding fault response

Description	Replacements	Refurbishments	Investment ($million, 2021)
Risk based asset management: wood poles	20,878	18,892	233.8

Source: Powercor
Notes: Forecast shown excludes real escalation; fault response is modelled separately (refer to PAL MOD 4.11 - Network faults - Jan2020 - Public).

Our pole replacement practices will also allow us to maintain the average age of our wood population as at December 2020. Although this was not a target of our amendments, we recognise this outcome is an important cross-check for our communities and demonstrates our commitment to maintaining the long-term resilience of our network.

Further details on our risk based asset management program, and the full justification for our additional pole investment, is set out in our pole replacement business strategy.[16]

Other high-volume, low-cost asset replacements

In addition to poles, much of our forecast replacement investment is for assets such as overhead conductors, service lines, fuses, surge-diverters, and pole-top structures (such as cross-arms attached to our poles). We typically replace these assets based on a 'find-and-fix' or reactive approach.

As shown in table 4.4, our forecast investment for these asset categories is largely consistent with our historical investment.

Table 4.4 Total lines replacement investment ($ million, 2021)

Asset category	2016–2021	2021–2026
Overhead conductor	41.2	43.5
Service lines	38.3	45.4
Fuses and surge diverters	30.6	29.7
Pole-top structures	76.3	81.3
Total	**186.4**	**199.9**

Source: Powercor
Note: Our pole-top structures and service line forecasts have been reduced to account for the expected overlap due to our increased pole replacement volumes. Forecast shown excludes real escalation.

15 For example, our intervention response may be to stake the pole rather than replace. The timeframe for intervention also depends on whether the classification of unserviceable is an immediate priority (i.e. replace in 24 hours, or replace with 32 weeks).

16 PAL BUS 4.02: CitiPower and Powercor, *Pole replacement program,* January 2020.

Our investment forecast for these asset categories is estimated using average actual replacement volumes over the four-year period spanning 2014/2015–2017/2018. As set out in our lines replacement model, targeted proactive intervention programs are also included in our replacement forecasts for additional safety-driven measures that are consistent with our AFAP obligations.[17] These programs are discussed below.

Stakeholder feedback

As part of our stakeholder engagement program, we undertook a series of deliberative forums with our customers. At these forums, we discussed several safety-driven programs that leveraged our smart meter investment to proactively identify hazardous assets.

To enable customers to fully understand and explore the investment options for delivering these programs, participants were briefed on the key challenges in delivering the program, and three to four options for investment going forward. Two of these safety programs were the replacement of twisted PVC service lines, and our neutral screen testing program (both discussed in further detail below).

The options presented for these programs included a status-quo option (i.e. consistent with our existing asset management approach), and incremental replacements to proactively reduce safety risk. Customers were provided with indicative bill impacts associated with each option, as well as the cumulative impact of selecting multiple safety programs throughout the entire forum.

Our customers were overwhelmingly supportive of using smart meters to detect faults for repair. Further, our customers wanted us to initiate these programs immediately, rather than wait until the 2021–2026 regulatory period.

Based on our customer feedback, we have brought forward the timing of many of these projects into the current regulatory period.

Service lines: neutral screen testing program

Since the introduction of smart meters in Victoria in 2009, we now have access to more and better data regarding the performance of our network. We are leveraging our smart meter investment to continuously improve how we manage our network—particularly the safety benefits we can now provide to our customers.

Our neutral screen testing (**NST**) program proactively detects hazardous neutral services by applying an algorithm to smart meter data that identifies particular voltage and current signatures (that are consistent with potentially faulty service connections). Faulty neutral connections can result in electric shocks to customers. As such, where our NST program identifies a potential fault, we remotely de-energise the site and dispatch a fault crew to inspect the connection.

As a result of our smart meter NST program, we are expecting to replace around 635 service lines per annum. These volumes are largely consistent with those observed since the program began in 2018, but represent a step-up relative to our previous inspection method.

Service lines: twisted PVC service line replacement program

Twisted polyvinyl chloride (**PVC**) grey service cables are a common type of service line installed throughout our network. As shown in figure 4.5, these connections use a double ended metal hook that is coated in insulating plastic to hold the service wires in position as they feed from the service span down to the customer's connection.

[17] PAL MOD 4.06 - Lines replacement - Jan2020 - Public.

Figure 4.5 Sample image: twisted PVC service line

Source: Powercor

The metal hook connection—commonly referred to as a 'dog-bone'—has a failure mode that can lead to a significant safety risk at the premise to which it attaches. With movement of the service over time, the metal hook can pierce the insulation of the service conductors and liven up any attached metal work (such as connected verandas or guttering).

There are over 94,200 PVC twisted grey services installed throughout our network, and when the extent of the safety risk associated with dog-bones was first identified in 2016, we inspected all of them. This inspection resulted in the replacement of over 4,000 high-risk services through to 2018. Our asset inspection policy also changed to require visual inspections of all services from underneath both ends of the 'dog-bone', rather than the previous practice of inspecting only from the connecting pole.

We initially presented to stakeholders our intention to continue our twisted PVC service line replacement program from 2021 onwards (for lower priority defects). However, our customers overwhelmingly supported this program, and we have since committed to increasing our replacement rate from 2019. The proposed capital investment across the 2021–2026 regulatory period, therefore, represents the continuation of this program.

Environmental management program

We are subject to both Victorian and Commonwealth environmental obligations, including the *Environment Protection Act* and the State Environment Protection Policies for noise, land, groundwater, surface water and air quality. Our replacement investment forecast includes projects required to continue to meet these obligations.

Historically, we have managed the risks associated with our environmental obligations primarily through a reactive approach consistent with the prevailing legislation. For example, we have investigated noise concerns associated with our zone substation transformers following a customer complaint.

From July 2020, the revised *Environment Protection Amendment Act 2018* will come into effect. As set out in the Regulatory Impact Statement (**RIS**), these revisions establish a modern regulatory approach focusing on preventing waste and pollution impacts, rather than managing any impacts after an event has occurred.[18]

[18] PAL ATT010: DELWP and EPA, *Regulatory Impact Statement: Proposed Environment Protection Regulations*, August 2019, p. 7.

In order to meet these new proactive compliance obligations, our investment forecast for the 2021–2026 regulatory period includes noise reduction and bunding programs at a number of high-risk zone substations. These sites have been identified based on a desk top study to determine the following:

- bunding—oil-leak risk rating, based on the likelihood of an oil-leak arising, and the potential damage to the surrounding environment
- noise—decibel exceedance and proximity to residential properties.

The cost for proactively addressing these risks is based on an assessment of least-cost compliance options. For our bunding works, these options typically consider and compare the installation of bunding with or without a stormwater management system. For our noise program, the site options range from enclosing part or all of the site, to asset replacement.

The full impact of these regulatory changes, and our monetisation of the likelihood and consequence of all risks, is set out in our attached environmental management business case.[19] A summary of the costs of this program are outlined in table 4.5.

Table 4.5 Compliance with new environmental obligations: total forecast investment, 2021–2026 ($ million, 2021)

Description	Investment
Noise compliance program	30.5
Bunding compliance program	17.3
Total	**47.8**

Source: Powercor

Notes: Increased operational expenditure is also required to meet our new compliance obligations in regards to increased monitoring and land contamination management. These costs are discussed in our operating expenditure chapter of this regulatory proposal. The forecast shown excludes real escalation.

4.1.2 Providing a safe network that mitigates bushfire risks

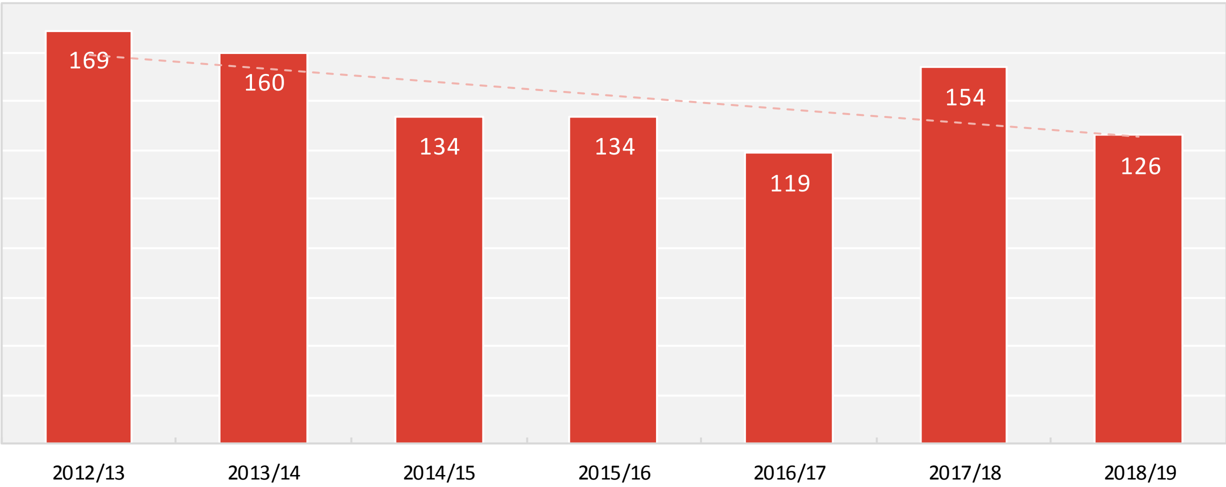
We operate a distribution network where the majority of our assets are located in designated high bushfire risk areas (**HBRA**). The unique combination of weather and vegetation that occurs in south-eastern Australia makes it one of the most bushfire prone locations in the world.

As any spark is a potential source of ignition, the consequences of a fault in our overhead electricity sub-transmission or distribution system can be catastrophic. The high temperatures, low humidity and hot gusty northerly winds that occur through summer and autumn produce a volatile fuel source that can ignite easily and burn fiercely. Such fires have caused enormous property, livestock and wildlife losses, together with loss of human life.

It is impossible to eliminate fire starts completely, but as shown in figure 4.6, the trend in ground fire starts from our assets is decreasing. This follows our investment, and that from the Victorian Government, of over $300 million to implement the Government's recommended response to the Victorian Bushfire Royal Commission.

[19] PAL BUS 4.01: Powercor, *Environmental Protection Amendment Act* 2018, January 2020.

Figure 4.6 The trend in asset-related ground fire starts is declining



Source: Powercor

Notes: The increase in 2017–2018 was primarily driven by extreme weather events in January and March of 2018. Forecast shown excludes real escalation.

Our approach to continue to effectively reduce the risk of bushfires from our network is set out in our BMP, which is approved by ESV.[20] Projects included in our BMP are compliance obligations under the *Electricity Safety Act 1998*.[21]

Stakeholder feedback

Our customers hold strong views that safety is a given, and is too important to be 'traded-off'. Throughout our engagement process, they emphasised that safety should always be our top priority and must be maintained or improved where possible.

In particular, bushfire mitigation projects were strongly supported in our deliberative engagement forums. Our customers typical response was that we should be bringing these projects forward. This included using new technology, undergrounding of assets and increased pole inspections. Some examples of our use of technology as part of continuous improvement practices include the following:

- development of a bushfire risk model (using modelling developed by CSIRO), to provide a quantitative understanding of the relative bushfire risk at any point on our network and facilitate improved asset management and operational decision making
- assessment and trial of HV covered conductor, which if successful, will provide an alternative solution to rural assets in designated electric line construction areas and other identified high risk fire areas
- evaluation and trial of early fault detection technology on single wire earth return (**SWER**) systems
- evaluation of additional non-destructive testing technologies for wood pole condition assessment
- development of smart meter signature detection algorithms to identify deteriorating LV switching devices
- development and trial deployment of broken conductor detection and isolation technology.

We have, however, had regard to affordability by not proposing to extend our program to retire our SWER network into the 2021–2026 regulatory period. Since 2014, the Victorian Government's powerline replacement fund (**PRF**) has funded the retirement of almost 300 kilometres of existing SWER lines in the designated highest consequence bushfire areas. The PRF is expected to conclude in 2020. If directed by ESV to continue these works, we will seek regulatory funding through the pass-through mechanisms set out in the Rules.

20 PAL ATT094: Powercor, *Bushfire Mitigation Plan 2019–2024*, January 2020.

21 *Electricity Safety Act 1998*, clause 113B(2).

The investment required to support many of the programs included in our BMP is set out in our attached bushfire safety model.[22] The investments allocated to our replacement expenditure program are further summarised in table 4.6. Based on our customer feedback, we have brought forward the timing of some of these projects into the current regulatory period (rather than commencing them from 2021 onwards).

Table 4.6 Bushfire mitigation program: total forecast investment, 2021–2026 ($ million, 2021)

Description	BMP reference	Investment
Replace wood cross-arms in electric line clearance areas (**ELCAs**)	6.12.9	3.2
Replace LV fuse switch disconnectors in ELCAs	6.12.7	3.7
Replace LV fused overhead line connector boxes (**FOLCBs**) in ELCAs	6.12.8	5.0
Mitigating REFCL reliability impacts	6.12.3	13.0
Early fault detection	6.12.5	2.7
HV covered conductor and broken conductor detection trials	6.12.6	2.1
Total		**29.5**

Source: Powercor
Notes: Forecast shown excludes real escalation.

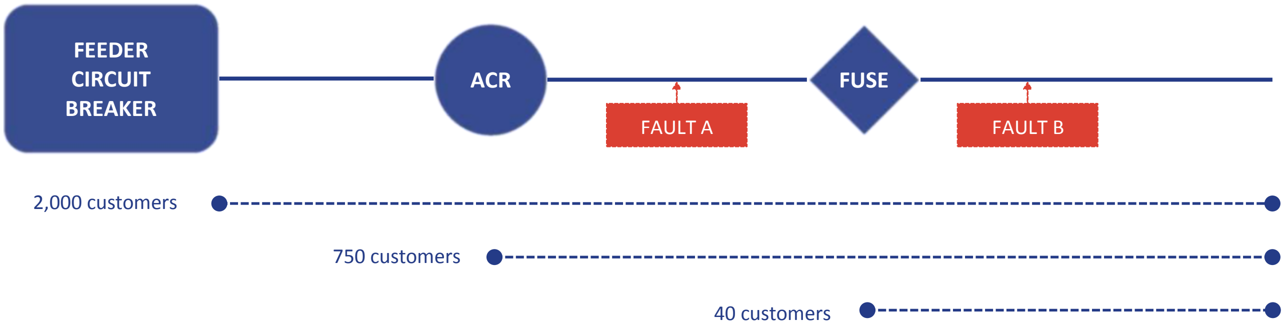
Mitigating REFCL reliability impacts

We are required to progressively install rapid earth fault current limiters (**REFCLs**) at 22 zone substations during 2018–2023 to comply with the Electricity Safety (Bushfire Mitigation) Amendment Regulations 2016 (**Amended Bushfire Mitigation Regulations**). A REFCL is a network protection device, normally installed in a zone substation, which can reduce the risk of a fallen powerline causing a fire-start.

The operation of a REFCL is designed to function before downstream protection devices have the opportunity to operate. In the example shown in figure 4.7, this means outages occurring downstream of our automatic circuit reclosers (**ACRs**) and fuses (i.e. fault A or B) are instead isolated by the REFCL at the circuit breaker. This results in more customers being taken off supply.

22 PAL MOD 6.09 - Bushfire safety - Jan2020 – Public.

Figure 4.7 Simplified example of protection devices and customer impact



Source: Powercor

Our experience with REFCLs on our network to date demonstrates that significantly more customers are being taken off supply for faults occurring downstream of ACRs and fuses. These outages have been characterised by the recent experience of our customers in Apollo Bay.

Stakeholder feedback

Our customers in Apollo Bay are protected by a REFCL installed at our Colac zone substation. This REFCL was commissioned in 2018.

Since commissioning this REFCL, our Apollo Bay auto-loop scheme has not been operable. Auto-loop schemes rely on ACRs to automatically switch supply after a fault. As a result, the community in Apollo Bay have experienced an increase in the number of outages.

The feedback from our customers has been widely publicised, particularly the impact on our business customers:

> *'We're trying to run businesses, we've got people's livelihoods that are going to be impacted significantly if something's not done.'*
>
> *'Obviously we're gearing up for a busy season and it's not just Apollo Bay. I imagine it's a lot of country towns where this system has been implemented, they're going to be in the same situation. We're going into our busiest time of the year, we're not going to be able to function, we're not going to be able to open the door.'*
>
> *'We can't get a generator because it's not worth it to outlay $10,000 to $15,000.'*
>
> *In winter the food can keep. But in summertime we have to throw everything out if it lasts too long.'*
>
> *'We've got 23 apartments here, [we've] got international guests that we're charging reasonable money – it's not a budget place – and they expect the air conditioners to work and the lights to work.'*

We listened to our customers and in September 2019 we chose to temporarily disable the Colac REFCL.

The impact to customers from the decline in reliability will worsen over time as more REFCLs are installed on our network. As such, we are working closely with specialist vendors to develop 'smart' ACRs, which are compatible with REFCLs (i.e. they will operate to isolate supply on the feeder, downstream of the circuit breaker, before the REFCL).

Replacing our existing traditional ACRs with smart ACRs would mitigate some of the reliability impact of REFCLs on our network. At this stage there is no equivalent 'smart' fuse, and consequently, customers located between the fuse and the 'smart' ACR on a REFCL network will still experience an outage.

A summary of our forecast investment in smart ACRs is shown in table 4.7. The full justification for this program is set out in our attached business case.[23]

Table 4.7 Replacement of ACRs in REFCL areas: total forecast investment, 2021–2026 ($ million, 2021)

Description	Volumes	Investment ($)
ACR replacements	216	13.0

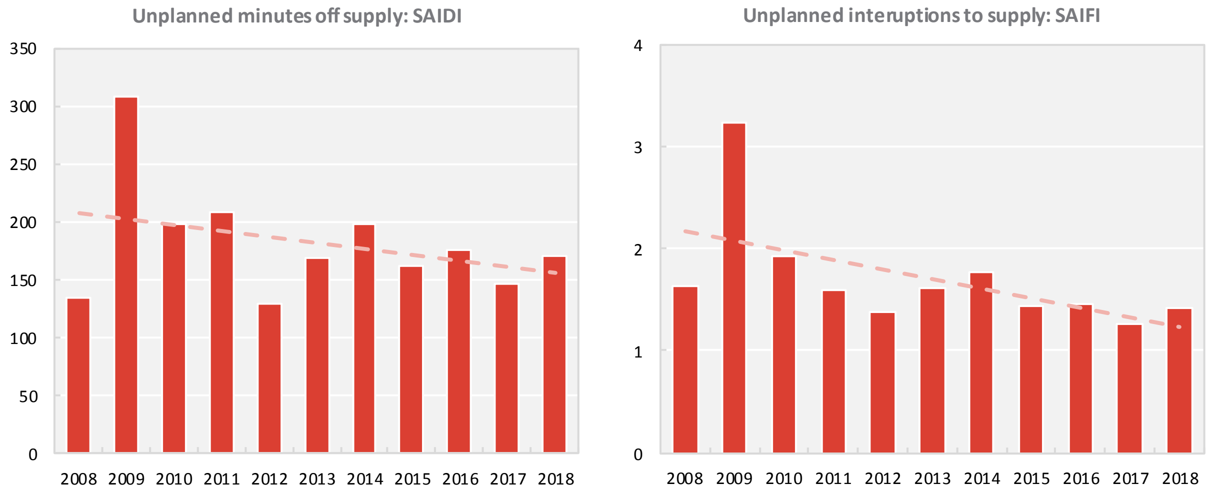
Source: Powercor
Notes: Forecast shown excludes real escalation.

4.1.3 Providing a reliable supply of electricity

Overall, the investments included in our regulatory proposal are designed to maintain both affordability and the long-term health of our electricity assets. This includes investments needed to maintain current reliability levels on average across our network (noting that factors such as the weather will still drive variances each year).

We will also work to improve reliability where our customers value the improvement more than the cost to deliver it, although these works do not form part of our investment forecast. As shown in figure 4.8, we have been improving our reliability and will strive to maintain this trend.

Figure 4.8 Unplanned outages a typical customer experiences (minutes off supply; number of outages)



Source: Powercor

23 PAL BUS 4.05: Powercor, *Mitigating REFCL reliability impacts,* January 2020.

Stakeholder feedback

We know from talking to our customers that network reliability is important. Along with affordability, it consistently ranked as the key output measure throughout our stakeholder engagement forums.

Specifically, our customers are generally satisfied with the level of reliability currently experienced. Around half our customers were willing to pay more for better reliability, whereas only 7% were prepared to pay less for lower reliability.

Many of our customers also expressed their support for improving reliability for worst-served customers. Although our regulatory proposal does not include such programs—due to balancing other considerations, including affordability—we have improved reliability in the current regulatory period by installing additional switches and monitoring devices. When there is an electricity outage, this equipment helps us restore supply more quickly by remotely identifying and segmenting fault locations for our field crews to attend.

In addition to speaking with our residential and business customers, our engagement included a network risk management workshop with key stakeholders to detail the risk monetisation approach used to justify many of our asset replacements (including zone substation transformers). This workshop was attended by the AER, Energy Consumers Australia, and representatives from ESV. As outlined in section 4.2, our risk monetisation approach is consistent with the AER's replacement planning practice note.

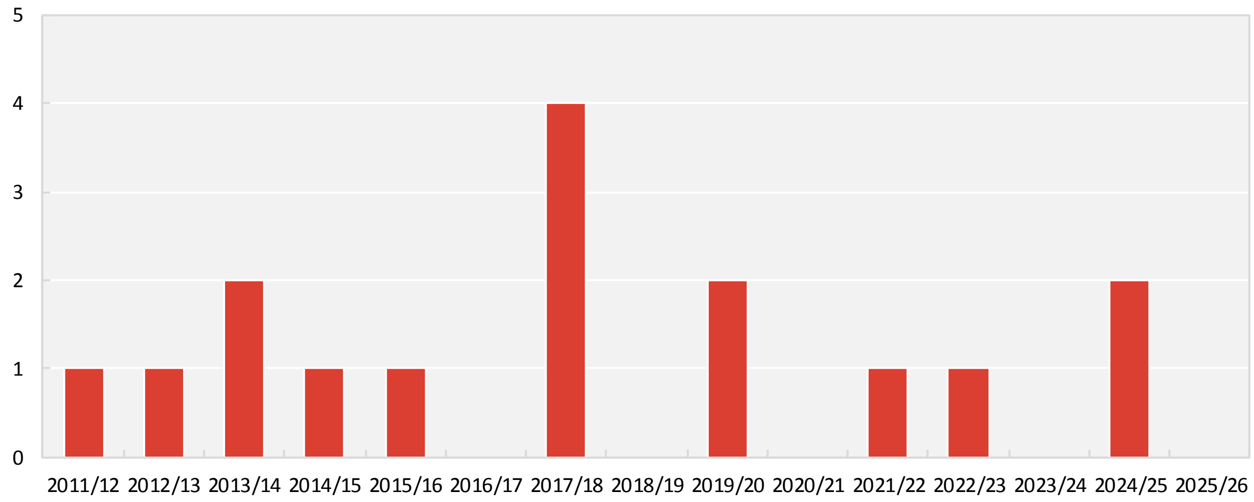
An overview of the key investments we will make over the 2021–2026 regulatory period to ensure we provide a reliable supply of electricity are discussed below.

Replacement of zone substation transformers

Our electricity network comprises 58 zone substations and 143 power transformers.

In the 2021–2026 regulatory period, we will replace one 66kV regulator and three of these zone substation transformers—two at our Robinvale zone substation, and one at our Warrnambool zone substation. As shown in figure 4.9, this replacement rate is in line with recent historical trends.

Figure 4.9 Historical and forecast transformer replacement volumes



Source: Powercor

Our approach to forecasting replacement investment for major plant is based on a monetisation of risk, and is discussed in detail in section 4.2.2. This approach recognises that should a transformer fail in service, the impact to customers and the community will vary based on the potential consequence in terms of safety, bushfire, environmental and financial impacts, and supply reliability.

Our risk assessment also has regard to the probability of an asset failing, which is a function of the asset's underlying condition. The condition of our assets is characterised by a health index, which is derived from our condition based risk management (**CBRM**) model.[24] At the forecast time of replacement, each of these transformers will be greater than 70 years old.

The justification for the replacement of each of the zone substation transformers included in our 2021–2026 replacement program is set out in our attached zone substation transformer risk monetisation justification document and models.[25] A summary of the total investment required for these works is set out in table 4.8.

Table 4.8 Transformer replacements: total forecast investment, 2021–2026 ($ million, 2021)

Description	Investment
Robinvale transformer no.1	3.9
Robinvale transformer no.2	3.9
Warrnambool transformer no.3	3.9
Inglewood regulator	1.3
Total	**12.9**

Source: Powercor
Notes: Forecast shown excludes real escalation.

Replacement program for high voltage air-break switches

In 2016, we experienced a number of safety incidents where expulsion interrupters fitted to HV switches failed when the switch was being opened. Expulsion interrupters are devices fitted to HV air-break switches that provide a second path for current to flow, with a spring-assisted extinguishing mechanism to break the arc once the main contacts are sufficiently far apart. These expulsion interrupters were introduced to our network in the early 1990s.

As a safety precaution, all HV air-break switches fitted with specific expulsion interrupters were tagged 'caution refer operations' (**CRO**). A CRO-tagged switch can only be operated when de-energised, or for specific types of expulsion interrupters—namely, DoubleBreak and EziBreak types—cannot be operated at all (i.e. they are deemed inoperable).[26]

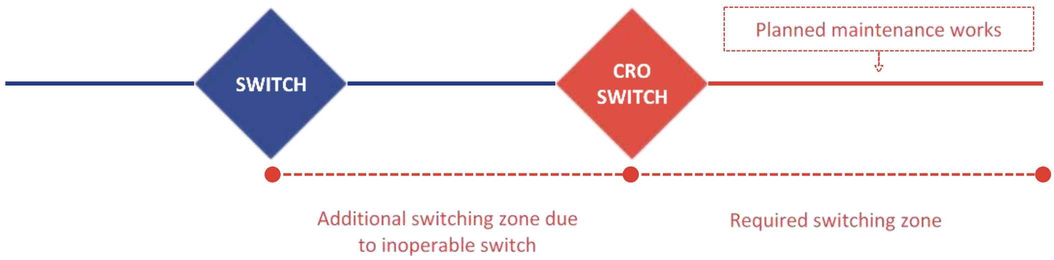
The impact on customers from a CRO-tagged switch is that they will experience more planned outages. For example, where the switch immediately upstream of planned works is deemed inoperable, a switch further upstream will need to be operated. As shown in figure 4.10, this would result in an additional switching zone of customers without supply.

24 The CBRM is a proprietary model developed by EA Technologies. The model is an ageing algorithm that takes into account a range of inputs to produce a health index for each asset in a range from zero to 10 (where zero is a new asset and 10 represents end of life). The health index provides a means of comparing similar assets in terms of their calculated probability of failure.

25 PAL BUS 4.03: Powercor, *Transformer risk monetisation and investment evaluation methodology*, January 2020; PAL MOD 4.05 - WBL transformer no.3 - Jan2020 - Public; PAL MOD 4.12 - IWD regulator - Jan2020 - Public; PAL MOD 4.13 - RVL transformer no.1 - Jan2020 - Public; PAL MOD 4.14 - RVL transformer no.2 - Jan2020 - Public.

26 CRO-tagged switches, however, can remain permanently closed, and do not pose a safety risk in this state.

Figure 4.10 Additional switching zone due to CRO-tagged switch



Source: Powercor

In total, 920 CRO-tagged air-break switches remain on our network. We have commenced a program to progressively replace these switches, and propose to continue these works over a 12-year cycle. This will reduce the minutes off supply our customers experience due to planned outages (whereas any reliability benefit for unplanned outages is expected to be zero, as fault current is interrupted by protective devices such as circuit breakers and ACRs rather than switches).

The investment required to support our replacement program over the 2021–2026 regulatory period is shown in table 4.79. Further detail on this program, and the costs and benefits of alternative options (including not replacing CRO-tagged switches), is provided in our attached business case and model.[27]

Table 4.9 HV air-break switches: total forecast investment, 2021–2026 ($ million, 2021)

Description	Investment
Continue to replace all CRO-tagged air-break switches over a 12-year period	6.9

Source: Powercor
Notes: Forecast shown excludes real escalation.

4.2 Our forecasting approach

Our forecasting approach is consistent with the capital expenditure objectives and criteria set out in the Rules, and the AER's expenditure forecast assessment guideline.[28]

4.2.1 Our forecast asset replacements volumes are consistent with our asset management framework

Our asset management framework aligns with the requirements of ISO 55001. This framework is the international standard in asset management.

The asset management framework describes the asset management system that is applied to our network assets. The framework includes our asset management policy, strategic asset management plan (**SAMP**) and detailed network asset management plans and strategies for all asset classes. Our asset management policy and SAMP have been provided as attachments to our regulatory proposal.[29]

27 PAL BUS 4.04: Powercor, *HV ABS replacement program*, January 2020; PAL MOD 4.02 - HV ABS replacement program - Jan2020 - Public.

28 Rules, clause 6.5.7(a) and clause 6.5.7(c).

29 PAL ATT020: Powercor, *Asset management policy*, January 2020; PAL ATT021: Powercor, *Strategic asset management* plan, January 2020.

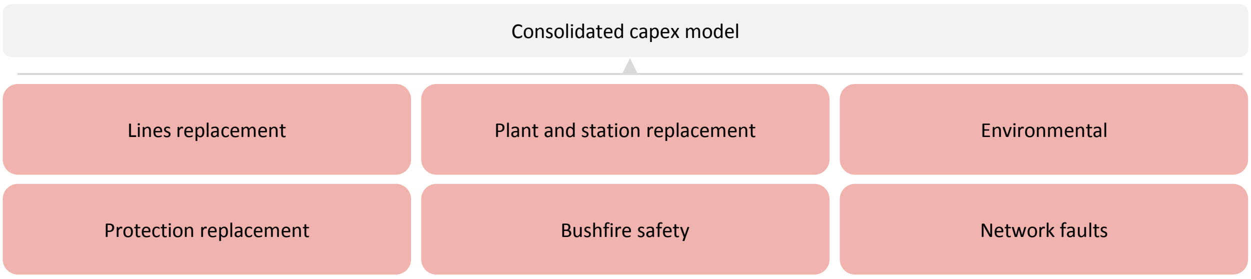
Our forecast asset replacement volumes are developed based on these asset management practices. In particular, we forecast asset replacement volumes based on three broad approaches:

- risk modelling/monetisation
- historical defect rates and forecast inspection volumes
- historical volume trends.

We apply these forecasting approaches to different asset and sub-asset categories based on the characteristics of the underlying asset. For example, we typically forecast high volume, low cost assets using observed historical trends (adjusted for any known change in operational policy or asset specific issues), or based on historical defect rates and forecast inspection volumes. In contrast, low volume, high value assets are typically forecast based on individual risk assessments and options analysis.

An overview map of our modelling approach for our replacement capital investment is shown in figure 4.11.

Figure 4.11 Capital expenditure model map: replacement investment



Source: Powercor
Notes: For simplicity, supporting models for individual business cases have not been shown.

4.2.2 Our risk-monetisation modelling is consistent with the AER's asset replacement planning note

Historically, our approach to forecasting replacement investment was based on an assessment of condition. For major plant, this approach was then supplemented with information on the load at a given site.

Our approach to forecasting replacement investment has recently become more sophisticated, and is now based on a monetisation of risk. Our risk-monetisation models ensure we invest only when the cost of replacing existing infrastructure is lower than the total value of the underlying risks. This means our customers pay no more than required on asset replacements.

Specifically, our approach to monetising risk when assessing investment decisions is to determine the annual asset risk cost (as shown in figure 4.12). This approach is taken for all identified failure modes for an asset, and the sum of the annual asset risk cost for all failure modes is compared to the annualised cost of the preferred option to determine the economic timing for any intervention. This approach is consistent with the AER's recent asset replacement guidance practice note.[30]

[30] PAL ATT175: Australian Energy Regulator, *Industry practice application note: asset replacement planning*, January 2019.

Figure 4.12 Calculation of annual asset-risk cost

Source: Powercor

A summary of how we determine the key input assumptions when calculating the annual asset risk cost is provided below. Further details are also set out in the relevant risk monetisation models for each asset, and/or the corresponding business cases.

Determining the probability of failure

The probability of failure is a key input assumption in any risk monetisation model. In the first instance, we use historical asset failure rates based on our own internal data.

We also use CBRM methodology to inform our probabilities of failure. Under this approach, the probability of failure is a function of an assets health score. The health score is informed by the normal expected life of the asset, its location and service history, its reliability performance, and observed condition and measured condition.

The relationship between the health score and probability of failure is such that the probability of failure is assumed to be constant for low health scores, but increases exponentially for higher health scores.[31] This is typical of reliability modelling, and represents that increasing degradation in asset condition will result in an escalating likelihood of failure.

The use of the exponential curve, however, can result in an acceleration effect once assets reach a high health score. For assets that are approaching their end of life, this run-away effect may provide a forecast probability of failure that would not reflect the deterioration expected to be observed in real life. To mitigate this impact (i.e. to minimise the potential for overstatement of the forecast probability of failure), an ageing reduction factor is introduced to modify the asset's rate of deterioration. This slows down the forecast ageing rate of any asset by flattening the exponential curve, especially (although not exclusively) where the health score is greater than 5.5.

Further technical detail on the derivation of probabilities of failure and health scores is provided in the risk evaluation supporting our zone substation transformer replacements.[32]

Determining the total expected cost of consequence

The total expected cost of consequence is equal to the likelihood of the consequence of a failure event, and the consequence cost of that failure. Our approach to determining these factors includes estimating outcomes for each potential failure mode across the risk categories set out in table 4.10.

31 Specifically, the relationship is based on a Taylor series for an exponential function.

32 See, for example: PAL BUS 4.03: Powercor, *Transformer risk and investment evaluation*, January 2020.

Table 4.10 Monetised network risk categories

Risk category	Example of value of risk
Network performance	Includes the value of unserved energy as a result of an unplanned outage; based on the value of customer reliability (**VCR**) estimated by AEMO (adjusted for inflation)
Bushfire	Includes the consequence value of a catastrophic bushfire set out in the Department of Economic Development, Jobs , Transport and Resources (**DEDJTR**) Regulatory Impact Statement (**RIS**), and disproportionate factors ranging from two to six depending on the geographical area[33]
Safety	Includes potential safety impacts to the public, or our workers, as a result of an asset failure; based on the value of a statistical life, and a disproportionate factor of three
Financial	Includes costs (both capital or operating) associated with the reinstatement or replacement of failed or damaged assets; typically based on expected scope and observed historical costs
Environmental	Includes costs of disposal of hazardous waste or environmental remediation works; typically based on expected scope and observed historical costs

Source: Powercor

Similar to our approach for estimating the probability of failure, in the first instance, we estimate the likelihood of any consequences of a failure event using our own internal data. For example, we use entry records (i.e. swipe card access) at a particular zone substation to determine the likelihood of our workers being on-site at the time of an asset failure.

4.2.3 Our unit cost forecasts are based on recent historical costs

As the most cost-efficient distributor in Australia based on AER benchmarking, our historical unit costs provide a reasonable basis for forecasting future investment requirements. For high-volume, low-value assets, these costs are typically determined as the average over the period 2015–2018. For low-volume, high-value assets, we typically forecast costs based on recent efficiently delivered projects of similar scope, size and geographic location.

Our historical costs, and therefore our forecast unit rates, also reflect rates from service providers that are derived from periodic tendering where available and appropriate. This includes our materials cost forecasts, which are procured through stringent contracting arrangements.

For clarity, we adjust our historical costs for forecast growth in real input prices over time, such as labour, materials and contracted services. Further discussion on our cost escalators is provided in chapter 9.

4.2.4 We will deliver our replacement program with support from our resource partners

Our labour force is structured to provide flexibility in managing labour resources. This allows us to deliver our total capital program, including the forecast increase in replacement investment. For example, our labour contracts include the following types:

- internal labour—these are permanent employees who provide the base level of labour required to provide a base level of labour services. To operate sustainably over the long term we must ensure we have secure

[33] PAL ATT114: ACIL Allen, *Regulatory Impact Statement, Bushfire Mitigation Regulations Amendment*, November 2015, p. 42.

access to a sufficient quantity of labour with the skills and knowledge required to deliver the minimum level of network and corporate services.

- local service area agents (**LSAA**)—these are third party owned and operated franchises that provide network services in specific network areas. LSAAs service different locations across our network and are generally assigned in the lower density network areas. LSAAs are selected through a five yearly market testing process.
- resource partners—these are third-party businesses, for example Lend Lease and Electrix, that provide additional labour services on an as needs basis. We utilise our resource partners to manage increased workloads that may arise for specific work programs. Resource partners are identified through a three yearly market testing process.
- contractors—we utilise contractors for skill-specific work including electrical work, fault response, metering works, civil works (i.e. digging works), traffic management, design work and vegetation management. We have different contractual arrangements with our contractors, ranging from longer term contracts with third party businesses to project-specific arrangements with individual Registered Electrical Contractors.

4.2.5 We tested our replacement investment forecast against the AER's repex model

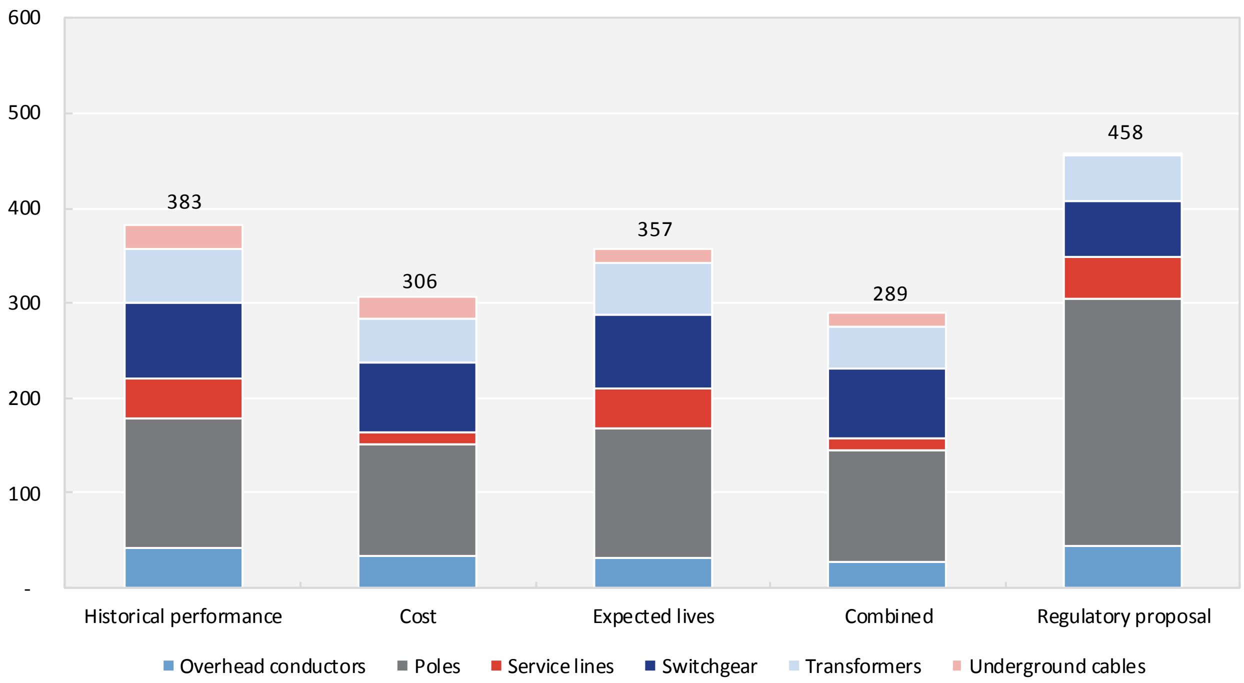
In addition to using a risk-monetisation framework to develop our replacement forecasts, we validated the prudency and efficiency of our replacement investment by comparing our outcomes to estimates from the AER's repex model. The AER's repex model provides a top-down assessment of 74% of our replacement investment forecast.

Modelled replacement investment

Our estimation of the AER's repex model scenarios is provided in figure 4.13. We engaged GHD to validate our application of this model which is available in in the repex modelling review attachment.[34]

[34] PAL ATT097: GHD, *Powercor 2021-26 Repex Modelling Review*, December 2019.

Figure 4.13 AER repex model comparison ($ million, 2021)



Source: Powercor

Based on the approach applied in its most recent draft decision for the South Australian and Queensland electricity distributors, the AER will compare our regulatory proposal forecast to the higher of the expected costs and expected lives scenarios. In the figure above, this will result in a comparison to the expected lives outcome.

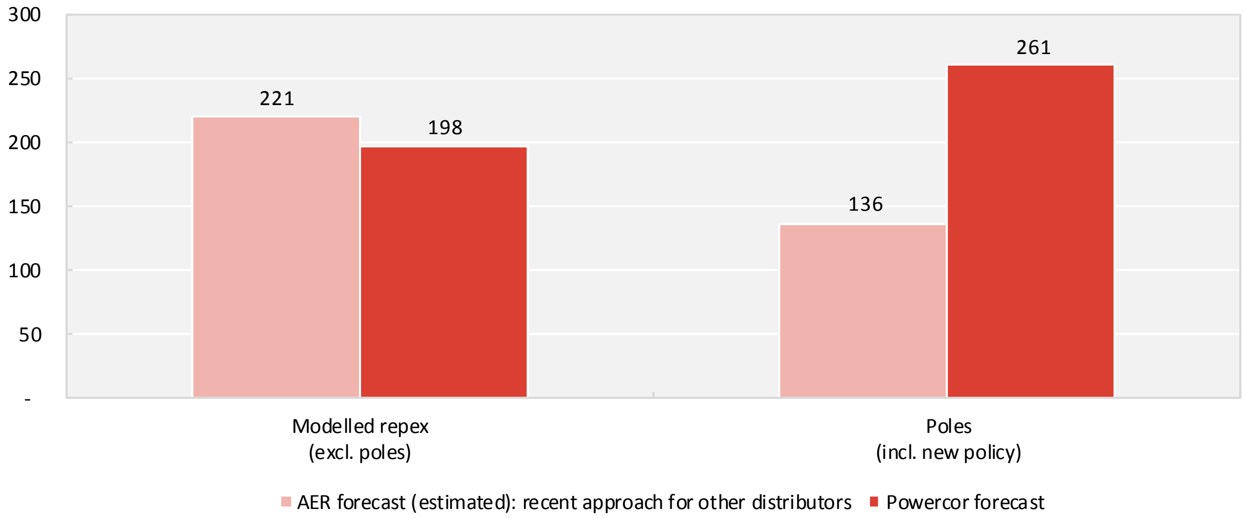
Our forecasts are reasonably consistent with the AER's expected lives outcome in most asset categories, except for poles. We provided an overview of our pole replacement program in section 4.1 (including the drivers of our additional replacement and reinforcement volumes).

We consider our risk monetisation modelling of asset categories and particular projects provides a more robust assessment of the prudency and efficiency of our investment forecast than the AER's repex model. The AER's repex model is a useful tool in identifying areas for further investigation, but it simplifies a complex range of factors to forecast the replacement of assets. In doing so, the AER's repex model has the following inherent limitations:

- the life of assets replaced in the past is assumed to be the same as for assets replacement in the future, such that the replacement investment projections are backward looking and may differ significantly from a truly optimal forward looking replacement program (particularly under an AFAP framework, where technological changes can continually drive further investment)
- the number of units replaced in the past is directly proportional to historical expenditure
- asset age is used as a proxy for the many factors that drive individual asset replacement, where other drivers such as safety or changing community expectations may be the primary driver for particular asset categories.

These factors are all relevant to the recent changes to our pole replacement practices. After accounting for these new policy and regulatory compliance obligations (which are not reflected in our historical expenditure), our investment is lower than the AER's repex model forecast. This is shown in figure 4.14.

Figure 4.14 AER repex model comparison, excluding poles ($ million, 2021)



Source: Powercor

Unmodelled replacement investment

The AER's repex model is not intended to cover our entire replacement investment forecast. For the 2021–2026 regulatory period, approximately 31% of our forecast replacement investment is 'unmodelled'.

The unmodelled portion of our replacement forecast includes our investment in replacing pole-top structures, protection equipment, environmental management, bushfire mitigation, and miscellaneous plant, station and civil works. A comparison of these costs for our current and forecast regulatory period is outlined in table 4.11.

Table 4.11 Comparison of unmodelled replacement investment ($ million, 2021)

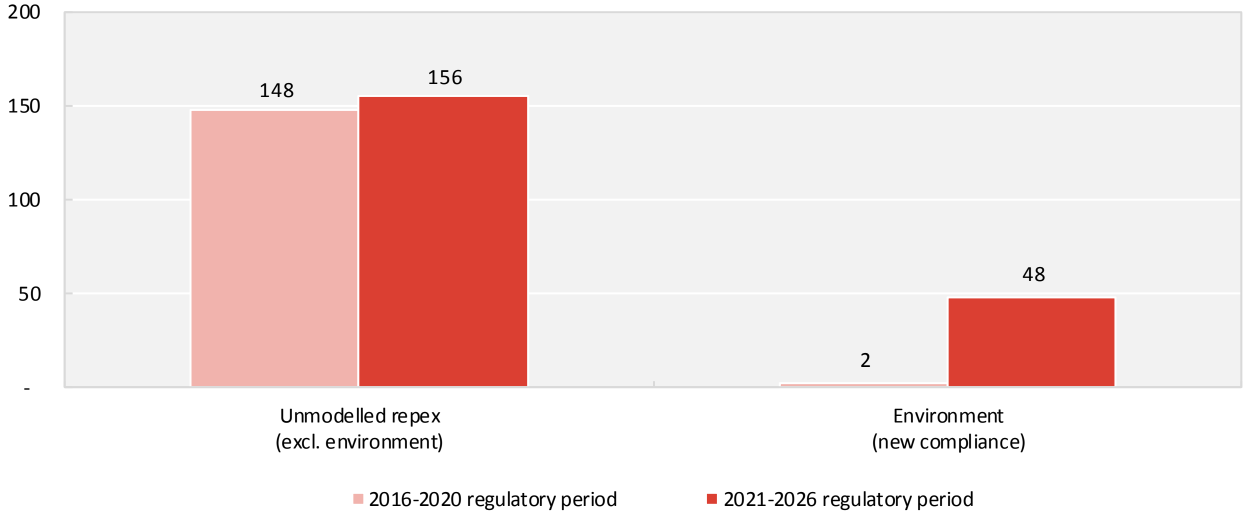
Description	2016–2020	2021–2026
Unmodelled replacement investment (total)	150	204

Source: Powercor

As shown in figure 4.15, with the exception of our environmental category, the total of our forecast unmodelled investment is consistent with our corresponding expenditure over the period from 2016–2020. The drivers of our environmental investment are set out in our attached environmental business case.[35]

[35] PAL BUS 4.01: Powercor, *Environmental Protection Amendment Act 2018*, January 2020.

Figure 4.15 Comparison of historical unmodelled replacement investment, excluding environment ($ million, 2021)



Source: Powercor

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5 Connections

Summary

After speaking with our customers, we have made improvements to our connection processes including reducing timeframes, improving communications, developing new business models to remove regulatory barriers to large scale renewable generation connections, and expanding contestability arrangements.

Construction activity in the western corridor of Victoria continues to underpin strong residential and commercial connection demands in our region. History has shown that even during major economic events impacting on housing markets, such as the Global Financial Crisis, the strength of the western corridor development and connection demands on our network have endured.

We have seen an influx of renewable generation connections due to lower costs and faster connection for small to medium solar and wind farms, new system strength requirements that are driving renewable generators to connect to the distribution (rather than transmission) network, higher wholesale electricity prices, the Victorian Government's Renewable Energy Auction Scheme and businesses seeking to deliver on commitments to be carbon neutral. This level of investment reflects the new policy setting and cultural norms, and is set to continue.

Notwithstanding the resilience of connections in our network, we have conservatively forecast our connections investment needs over the 2021–2026 regulatory period to in line with our historical investment. This is underpinned by independent and robust construction activity forecasts undertaken by the Australian Construction Industry Forum and historical investment needs; an approach previously accepted by the AER.

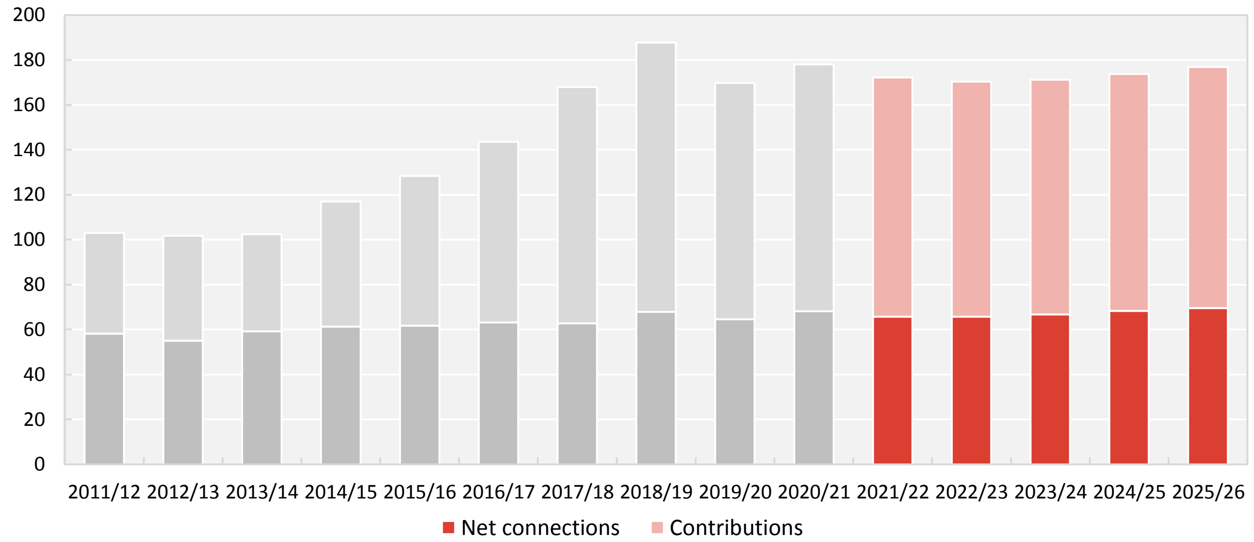
We have cross checked our forecast with a range of other approaches and found ours to be at the lower end.

This chapter sets out the investment we will make over the 2021–2026 regulatory period to meet our customers' connection requirements and support our customers' energy needs:

- in section 5.1 we present our investment forecast and the key drivers in our network
- in section 5.2 we outline our forecast approach and cross check our forecast with other approaches.

Figure 5.1 shows our forecast of gross and net connections. Net connections are net of the contributions we receive from connecting customers.

Figure 5.1 Gross and net connection investment forecast ($ million, 2021)



Source: Powercor
Notes: 2018/19 is an estimated actual, 2019/20 is the first forecast year. Forecast shown includes real escalation.

Table 5.1 outlines the connection forecast by its components.

Table 5.1 Connection investment forecast ($ million, 2021)

Year	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Gross connections	172.2	170.4	171.3	173.8	176.8	864.5
Gifted assets	48.4	49.1	49.9	50.6	51.2	249.1
Cash contributions	80.4	78.2	77.7	78.2	79.7	394.3
Rebates	22.3	22.6	23.0	23.3	23.6	114.8
Net connections	65.7	65.7	66.7	68.3	69.5	335.9

Source: Powercor
Notes: Net connections equal gross connections less gifted assets less cash contributions plus rebates. Forecast shown includes real escalation.

5.1 What we plan to deliver

Our focus over the 2021–2026 regulatory period is making efficient and timely connections. This section outlines the way in which:

- stakeholder engagement has driven improvements in our connection processes
- our investments will:
  - deliver more connections to power customers' everyday activities (high volume connections)
  - facilitate infrastructure growth (low volume connections)
- we will trial new models to streamline renewable generation connections
- our connection policy will continue to ensure customers pay for their fair share.

5.1.1 Stakeholder engagement has driven improvements in our connection processes

In 2016 we transformed the way we process connections by launching eConnect—our online portal to submit connection requests, seek solar pre-approval and allow us to better manage connections workflow. We also started our online mySupply platform to streamline customer initiated augmentation works. These tools have simplified the connection process and led to operational efficiencies, which have translated into lower costs for our customers.

Stakeholder feedback

From our residential surveys, around one in five respondents had experienced a connection. Further, 81% of these customers indicated they were satisfied with the timeframe and process. Unsatisfied respondents sought a quicker connection and better communication.[36]

This customer engagement highlighted drawbacks in our online portal, such as system operations issues that could lead to double booking connection appointments and in turn cancelling an appointment. We are now fixing this issue.

Additionally, we are working to better link multiple connection works at the same site (e.g. an asset relocation and a new connection) within our systems. These changes will ensure we communicate better with our customers.

In 2019 we spoke with developers, who considered connection processes could cause them delay in completing their developments. In response, we have made the following commitments to them and the Essential Services Commission:

- connecting developments to our network ('tie-ins') within 20 business days
- undertaking connection audits within 5–8 business days
- undertaking design approvals within 20 business days
- offering customers more choice by extending contestability to master designs.

Through responding to our customers, over the 2021–2026 regulatory period we will continue supporting our customers by connecting them faster than ever.

5.1.2 High volume connections—delivering connections to power customers' everyday activities

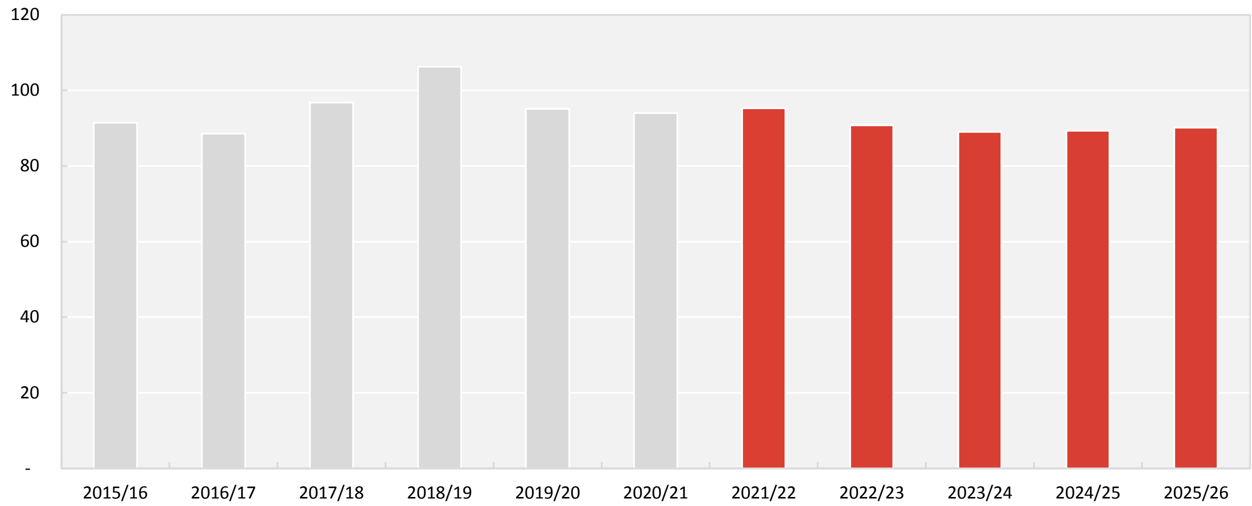
Improved services are critical given the sustained connections volume in our network. We expect to connect 114,000 new households over the 2021–2026 regulatory period.[37]

'High volume' connections consist of residential and small to medium business connections. Our forecast high volume connection demand is based on applying construction activity forecasts that have been independently undertaken by the Australian Construction Industry Forum (**ACIF**), as discussed more in section 5.2.1. Figure 5.2 outlines our high volume connection investment trend and forecast.

[36] PAL ATT125: Woolcott, *Powercor Residential Survey results*, July 2018, p. 26.

[37] Based on applying ACIF growth rates to historical connection volumes. Includes alternative control connections.

Figure 5.2 High volume connection investment ($ million, 2021)



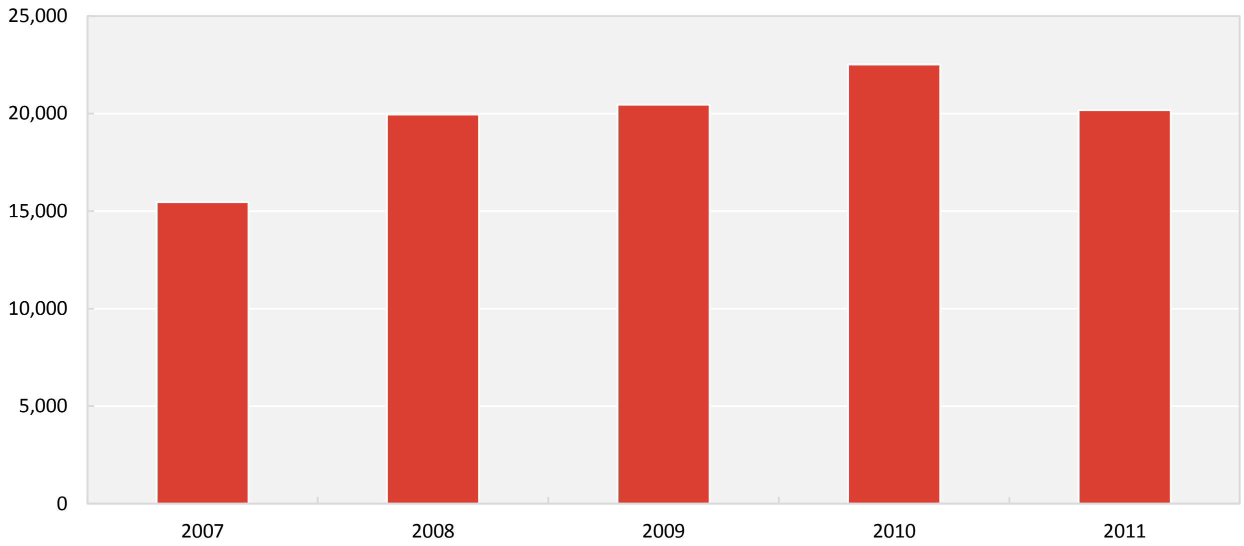
Source: Powercor
Notes: 2018/19 is an estimated actual, 2019/20 is the first forecast year. Forecast shown excludes real escalation.

We have been very conservative by forecasting a tapering off of our high volume connection investment over the 2021–2026 regulatory period. From 2016/17 to 2018/19, connection investments have been increasing. Under our forecasting approach discussed in section 5.2, we have forecast a step down in 2019/20, and then a further tapering off in the middle of the 2021–2026 regulatory period.

This forecast is very conservative when considered in the context of the resilience of high volume connection activity in our network. For example, 2018 and the first half of 2019 was characterised by declining housing prices in Victoria, which has largely stabilised in the latter part of 2019. Notwithstanding the housing price moderation, the demand for high volume connections over this period continued to swell. In fact, as shown in figure 5.2 above, 2017/18 and 2018/19 connections investment was higher than the preceding years.

This trend is also consistent with history which shows that even during and in the years following the 2007–2008 Global Financial Crisis, residential demand in our network area grew as shown in figure 5.3.

Figure 5.3 Residential connection volumes



Source: Powercor RIN data
Notes: Includes connections that are now classified as alternative control.

The robustness of our high volume connection demand in our network is largely because of strong housing growth experienced in Victoria's western corridor. Connection demand in this region is driven by the continued search for more affordable housing and access to public transport, and immigration. Residential construction activity in this area is forecast to grow by 12% over the 2021–2026 regulatory period.[38] We connected 482 new residential estates in 2018, 487 over 2019 and the industry has informed us the number is likely to be similar in 2020.[39]

Further information on construction activity trends is available in ACIF's report (attached).[40]

5.1.3 We are underpinning Victoria's leading renewable energy and infrastructure plans

We continue to underpin Victoria's leading renewable energy and infrastructure plans and the jobs that come with it through our low volume connection investment. Low volume connections are typically used for infrastructure projects and industrial customers. We generally support these projects by making construction supply available, providing permanent supply once the project is completed or relocating existing assets to accommodate the project.

Figure 5.4 outlines our low volume connection forecast. We note we have excluded the investment we have been undertaking to underground single wire earth return (**SWER**) lines in high bushfire risk areas from both the historical and forecast investment. This investment was driven by the Victorian Government's Powerline Replacement Fund and at this stage we do not expect this program to be continued over the 2021–2026 regulatory period.[41]

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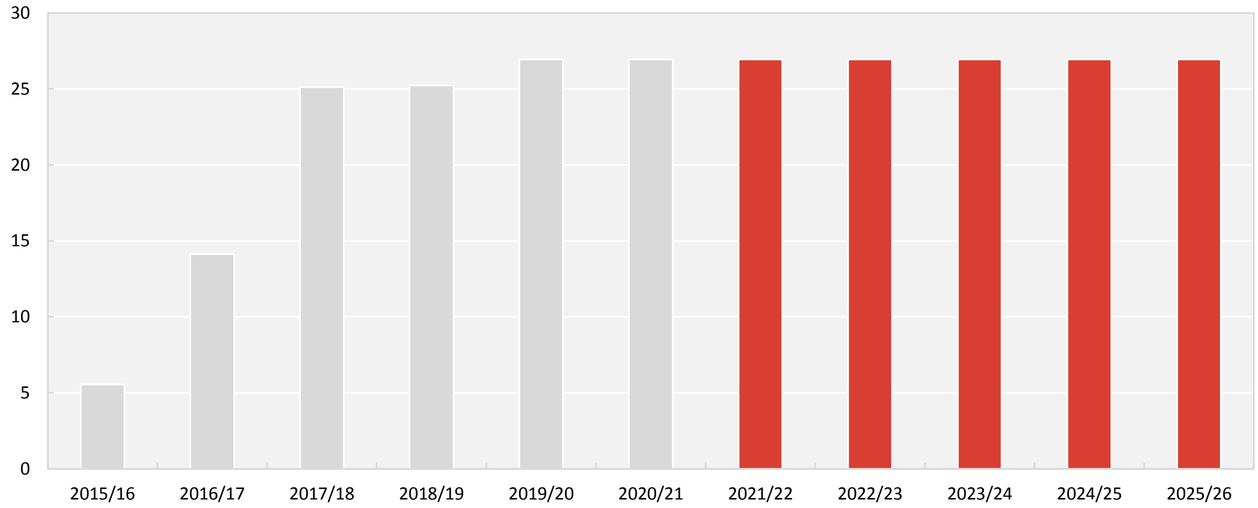
38 ACIF growth forecasts for the Western suburbs.

39 2019 volumes are 417 to the end of October 2019, and then annualised.

40 PAL ATT098: ACIF, *Australian Construction Market,* May 2019.

41 We will look to include this in the forecast if this changes before the revised proposal.

Figure 5.4 Low volume connection history and forecast ($ million, 2021)

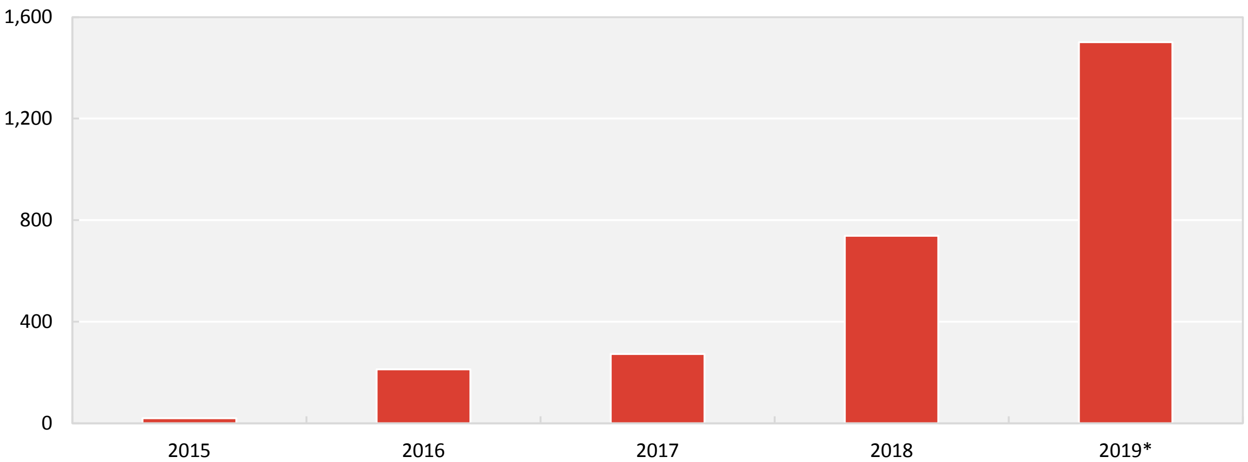


Source: Powercor
Notes: Forecast shown excludes real escalation

The primary driver of low volume connections investment is connecting renewable generation to the network. This investment has been increasing rapidly and this new level is set to continue.

Our network covers some of the best renewable resource areas in Victoria. Wind generation has been mainly focused in the south of our network around Terang, Ballarat and Horsham, and around Bendigo in central Victoria. Solar generation is focused in the north around the distribution systems near Wemen, Red Cliffs, Kerang and Shepparton. Figure 5.5 shows the actual amount of renewable generation we have connected each year from 2015.

Figure 5.5 Renewable generation connected (MW)

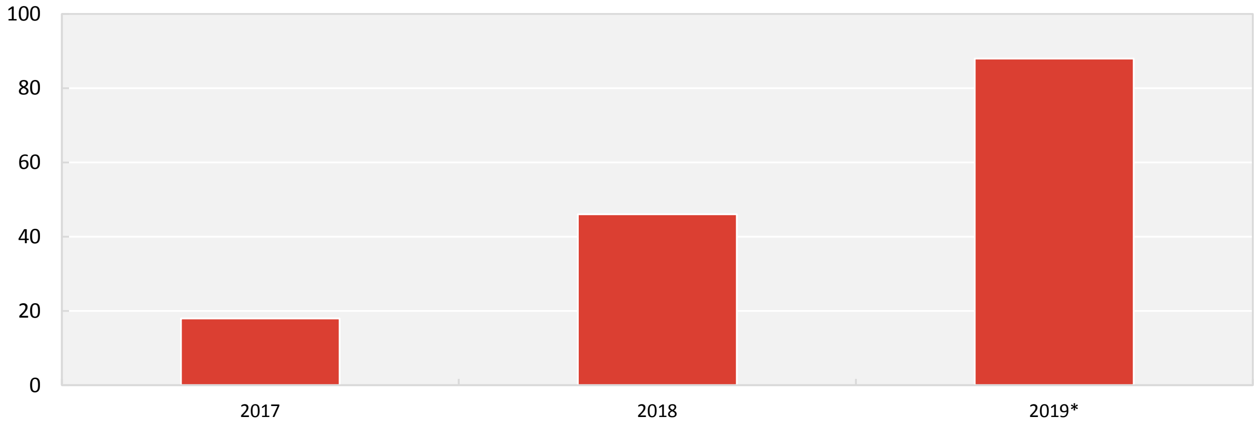


Source: Powercor
Note: 1,126 MW connected to end of August in 2019. This has been annualised by escalating by one third.

The significant step up in 2018 and 2019 will be sustained over the 2021–2026 regulatory period as it reflects new policy setting norms and market conditions as described below.

The first factor driving more renewable generation connections is changes to the Rules. In 2017, the Australian Energy Market Commission (**AEMC**) released a package of system strength reforms.[42] This included new obligations on transmission network service providers (**TNSP**) to maintain system strength resulting from new non-synchronous (e.g. renewable) generators. In practice, this has meant from July 2018, TNSPs have required new renewable generators to install or pay for equipment to ensure system strength is maintained. As embedded generators less than 5MW are not subject to the same stringent requirements, we have seen a rise in the number of embedded generation connections to our network.[43] This is illustrated by figure 5.6 which shows a doubling each year in the number of connection applications below 5MW from 2017 to 2019.

Figure 5.6 Number of connection applications to our network under 5MW



Source: Powercor
Note: 66 applications received to end of August in 2019. This has been annualised by escalating by one third.

The second factor driving new renewable generation is higher wholesale prices. After the Hazelwood generation closure in 2017, average wholesale prices in Victoria increased rapidly, which has encouraged the development of more renewable generation. Price pressure is not set to ease with the planned closure of the Liddell coal generator (in NSW) in 2022. The higher wholesale prices have made viable a number of new generators connecting to our network. Figure 5.7 shows the average historical wholesale price prevailing in Victoria as published by the Australian Energy Market Operator (**AEMO**).[44]

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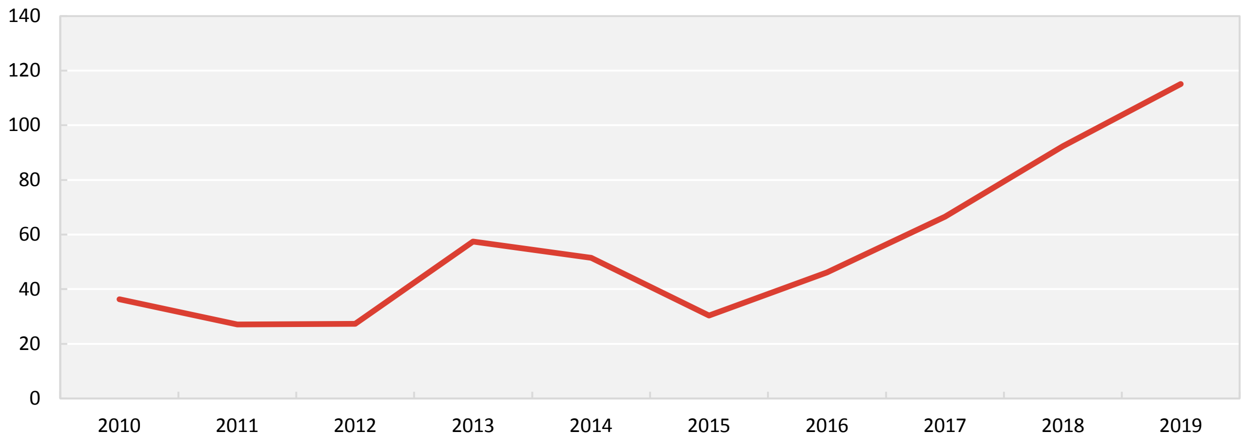
42 PAL ATT091: Australian Energy Market Commission, *Rule determination: National Electricity Amendment (Managing power system fault levels) Rule, September 2017*; PAL ATT040: Australian Energy Market Operator, System strength impact assessment guidelines, June 2018.

43 PAL ATT234: Australian Energy Market Operator, *Guide to generation exemptions and classification of generating units,* 16 November 2018. 'Where the combined nameplate rating of generating units or generating systems that are connected to a distribution system or transmission system through an embedded network is less than 5MW at the parent connection point, the person who owns, operates or controls these generating units or generating systems will be automatically exempt from the requirement to register as a Generator.'

44 PAL ATT235: Australian Energy Market Operator, *Data dashboard*.

Figure 5.7 Average Victorian wholesale electricity price ($/MWh)



Source: AEMO

The third factor is the Victorian Government's Renewable Energy Auction Scheme, which is designed to ensure Victoria meets its legislated commitment under the *Renewable Energy (Jobs and Investment) Act 2017* that 40% of electricity generated in Victoria is renewable.[45] It allows renewable generators to bid for the electricity price they require for their development to proceed, with the Victorian Government offering contracts for difference between the bid price and wholesale electricity price. The generators awarded contracts under the Victorian Government's first auction, held in 2018, are yet to connect (the first was due for connection at the end of 2019 but has been delayed). This means renewable connection expenditure will increase from its historical level.

And finally, new renewable generation is being driven by businesses seeking to achieve carbon neutrality, which is driving a market for renewable generation in parallel to the wholesale market.[46]

With respect to non-generation low volume connections, slower economic growth and low borrowing costs have led to robust public infrastructure spending. Public work grew by 22% in 2017 to reach $67 billion, boosted by sector investment in transport, energy and water infrastructure. There are many new major projects being added to an already solid pipeline. In Victoria, the raft of major infrastructure projects and other public investment activities has been termed 'Victoria’s Big Build'.[47] Some of the projects we will be supporting in our network area over the 2021–2026 regulatory period include Victoria's airport link and the new Victorian Government hub in Ballarat.

There is also mounting pressure on the Federal Government to ramp-up investment in public infrastructure projects to boost economic activity.[48] While the Federal Government' pledge to bring the budget back into surplus by 2019/20 is currently taking primacy, should the economy continue to slow it will be forced to fill the hole left by private infrastructure expenditure reductions.

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45 PAL ATT236: Department of Environment, Water, Land and Planning, *Victorian Renewable Energy Auction Scheme*, 2018.

46 PAL ATT237: The Guardian, *Coles signs long-term contract for electricity from three new solar farms*, August 2019.

47 PAL ATT050: ACIF, *Australian Construction Market Report*, November 2018.

48 PAL ATT042: Reserve Bank of Australia, Philip Lowe Governor, *Opening Statement to the House of Representatives Standing Committee on Economics*, August 2019.

5.1.4 We have listened to our customers and are developing new connection models

In support of the transition to a renewable sector, from 2019/20 we will be creating a new 'opt-in' process asking interested renewable developers in areas of major network constraint to inform us of their interest in developing projects. After gathering information on generation project locations and sizes we will develop connection solutions that seek to connect as many projects in the most efficient manner. Through this innovative approach we expect to:

- formalise a transparent process for collaboration between generation developers
- lower the amount of total network investment required to connect renewable projects to the network
- achieve fairer prices for renewable generators—rather than the first generator seeking to connect being required to pay for any major network upgrades alone, these will be spread across all projects
- create more generation connections as areas with constraints that previously acted as barriers for single projects are removed by collaboration and cost sharing.

Stakeholder feedback

In our deliberative forums, customers supported us developing energy hubs to connect more renewable generation. Customers were generally willing (62%) to underwrite the investment, with generators paying customers back as they connect.

However, because generators financially benefit from being connected to the network, we consider it fairer they pay in full for their connection. Therefore, we did not fully implement customer feedback in this respect. Notwithstanding this, our approach addresses the inequity between generators (i.e. first mover disadvantage) which our customers were concerned would act as a disincentive to renewable generation.[49]

5.1.5 We ensure that our customers make fair contributions to their connections

In 2018, we published and sought feedback on our draft connection policies (together with our draft proposal).

Our connection policy has been made in accordance with the AER's connection charge guideline. We have not made material changes to this policy from the 2016–2020 regulatory period. We will continue to offer two types of connection services; basic and negotiated. Customers requiring a basic connection will pay a fixed fee to cover the cost of installing a dedicated service line. Negotiated connections contribute to network upgrade costs based on the capacity of their connection in accordance with the AER's cost-revenue test.[50] This policy also outlines the circumstances when customers (typically developers) build assets and gift them to us and receive a rebate towards their cost of connection.

As part of this regulatory submission we are seeking AER approval of our connection policy and the Model Standing Offers (**MSO**) that most customers agree to when seeking a connection (attached).[51]

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49 PAL ATT082: Woolcott, *Investment Options Forums Report prepared for CitiPower, Powercor and United Energy,* September 2018, pp. 45-47.

50 Compared to our current connection policy, we have escalated the marginal cost of reinforcement (**MCR**) by inflation only. We note that any decrease/increase to the MCR will increase/decrease our net connection forecast.

51 PAL ATT033: Powercor, *Connection policy*, December 2019. PAL ATT034: Powercor, *Model Standing Offer with micro embedded generation (MEG)*, September 2019; PAL ATT035: Powercor, *Model Standing Offer without micro embedded generation (MEG),* March 2019.

5.2 Our forecasting approach

This section outlines our approach to forecasting high volume connections, low volume connections, customer contributions, gifted assets and rebates, and unit costs. We also cross check our forecasts against a number of metrics.

We applied different forecasting approaches to our high volume and low volume connections. Table 5.2 summarises the approach applied under each of the AER's regulatory information notice (**RIN**) categories.

Table 5.2 Forecast approach

Connection type	Description	Forecast approach
Residential	Simple connection LV	NA—classified as alternative control
	Complex connection LV	High volume—ACIF growth rates
	Complex connection HV	
Commercial/industrial	Simple connection LV	NA—classified as alternative control
	Complex connection HV (customer connected at LV, minor HV works)	High volume—ACIF growth rates
	Complex connection HV (customer connected at LV, upstream asset works)	
	Complex connection HV (customer connected at HV)	Low volume—bottom up build/historical average
	Complex connection sub-transmission	
Subdivision	Complex connection LV	High volume—ACIF growth rates
	Complex connection HV (no upstream asset works)	
	Complex connection HV (with upstream asset works)	
Embedded generation	Simple connection LV	Low volume—bottom up build/historical average
	Complex connection HV (small capacity)	
	Complex connection HV (large capacity)	
Quoted services[52]	Connection works that are customer funded	High volume—ACIF growth rates

Source: Powercor

[52] A standard control connection service that we report as a quoted service for RIN purposes.

5.2.1 Independent forecasts of connection drivers underpin our high volume forecasts

For high volume connections we have applied forecasts undertaken by ACIF to our historical connection volumes. This approach:

- uses forecasts of construction activity, which underpins high volume connection volumes
- is based on robust, widely used and independent forecasts
- has been accepted by the AER—this approach was proposed by United Energy for its 2016–2020 regulatory period and was accepted by the AER[53]
- has been applied consistently by CitiPower, Powercor and United Energy in their 2021–2026 regulatory proposals.

The ACIF forecasts are prepared by combining macro-economic forecasts of the domestic and international economy with information about the projected share of construction activity by sector and by region. The forecasts use the latest evidence from the Australian Bureau of Statistics (**ABS**) of residential building, non-residential building and engineering construction.[54] The forecasts are undertaken bi-annually for the two regions—'Melbourne' and 'rest of Victoria' as defined by the ABS—for 18 sectors of the economy.

ACIF's forecast for the Melbourne and rest of Victoria regions capture broad areas and are appropriate to apply to networks experiencing average connection activity. Our network, however, is experiencing more significant growth in the western corridor as outlined in section 5.1.1. The effects of this would be lost by applying a rest of Victoria average. Therefore, we sought ACIF to provide forecasts specifically for our network area using its standard forecasting approach. This forecast and accompanying ACIF report are attached with our regulatory proposal.[55]

To determine our connections investment forecast, the ACIF forecast have been applied in the following way:

- we have mapped ACIF's sector forecasts to the connection categories we use within the business, and then to the AER's RIN categories. We have undertaken this mapping in accordance with the main drivers of our connections. For example, ACIF's 'Residential New Houses' subcategory has been matched to our function code '102—LV Supplies to 63kVA'. This in turn is mapped to RIN categories 'Residential Complex Connection LV' and 'Residential Complex Connection HV'. We note our mapping is the same as applied in the 2016–2020 regulatory proposal (with the exception of co-generation which has been updated to reflect changing trends), which the AER accepted.[56] Our full mapping is outlined in our connections model.[57]

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53 PAL ATT239: Australian Energy Regulator, *Final Decision: United Energy distribution determination 2016 to 2020, Attachment 6 – Capital expenditure*, May 2016 , pp. 36, 39, 40. In addition to providing a robust and independent forecast, this approach was selected over that proposed by CitiPower's and Powercor's 2016–2020 regulatory proposal because their forecasts were not accepted by the AER.

54 PAL ATT098: ACIF, *Australian Construction Market Report*, May 2019.

55 PAL ATT110: *Building and construction activity forecasts for the Powercor electricity distribution region*, March 2019. PAL ATT112: ACIF, *Forecasts PCR regions*, March 2019.

56 PAL ATT207: Australian Energy Regulator*, Preliminary decision Powercor distribution determination 2016−20; Attachment 6 − Capital expenditure,* October 2015, p. 81. The AER stated 'We have assessed the Powercor mapping of the residential, commercial/industrial and subdivision categories and the descriptions of the internal function codes. Overall we consider that the mapping represents a reasonable allocation between the residential, commercial/industrial and subdivision connection categories and Powercor's internal function codes'.

57 PAL MOD 5.01 - Connections - Jan2020 – Public.

- for the first year of forecast connection volumes (2019/20) we have used the average prevailing connection volumes over 2015/16–2018/19. We note this is a very conservative starting point as it results in a drop from our current connection volumes. Nevertheless, an average has been used for setting the base year because:
  - some connections categories experience relatively low connection volumes meaning a single year may not represent the actual number of expected connections (i.e. smoothing to cater for annual volume volatility)
  - connections may begin in one year and finish in the next meaning any single year may not be a good representation of the connections work undertaken.
- from then onwards, ACIF growth rates have been applied to the preceding year's volumes.
- our unit rates are the actual average prevailing unit rates over 2015/16–2018/19 for high volume connections. These are calculated as connection investment over 2015/16–2018/19 divided by the number of connections over 2015/16–2018/19 for each of our function codes. As with the volumes, an average is used to account for the different mix and hence cost of connections that may occur in a single year. On balance, we consider a longer average would not reflect current market conditions. This averaging period is the same applied across most of our capital expenditure categories.

Our forecasting approach is further outlined in our connections model.[58]

5.2.2 Our low volume forecasts are underpinned by known connection projects and history

Our low volume connection categories are the following RIN categories:

- commercial/industrial complex connection HV (where the customer is connected at HV)
- embedded generation.

We have forecast low-volume connections based on a bottom up build, however, where connection projects are unknown, we have used historical investment. This is because we rarely receive inquires for the entire regulatory period by the time of submitting the initial regulatory proposal. The AER has previously considered it appropriate to trend forward connections investment when connection projects are unknown.[59] Consistent with our previous approach, we have separately forecast the low volume connections below and above $2.5 million.[60] This approach is preferable to construction activity forecasts because these large and low volume connections are typically not directly related to broader construction activity and are driven by specific policies and customer needs.

For 'commercial/industrial complex connections HV', historical average expenditure from 2015/16–2018/19 is used. In our revised proposal we expect to have more visibility of the low volume connections required over the next regulatory period.

Our approach to forecasting embedded generation is similarly based on the higher of a bottom-up build and historical expenditure, however, we have only based historical expenditure on the investment that occurred in 2018/19. As outlined in section 5.1.3, this is because the Victorian Government's Renewable Energy Auction Scheme, AEMC rule changes and higher wholesale prices have resulted in a structural break from the investment

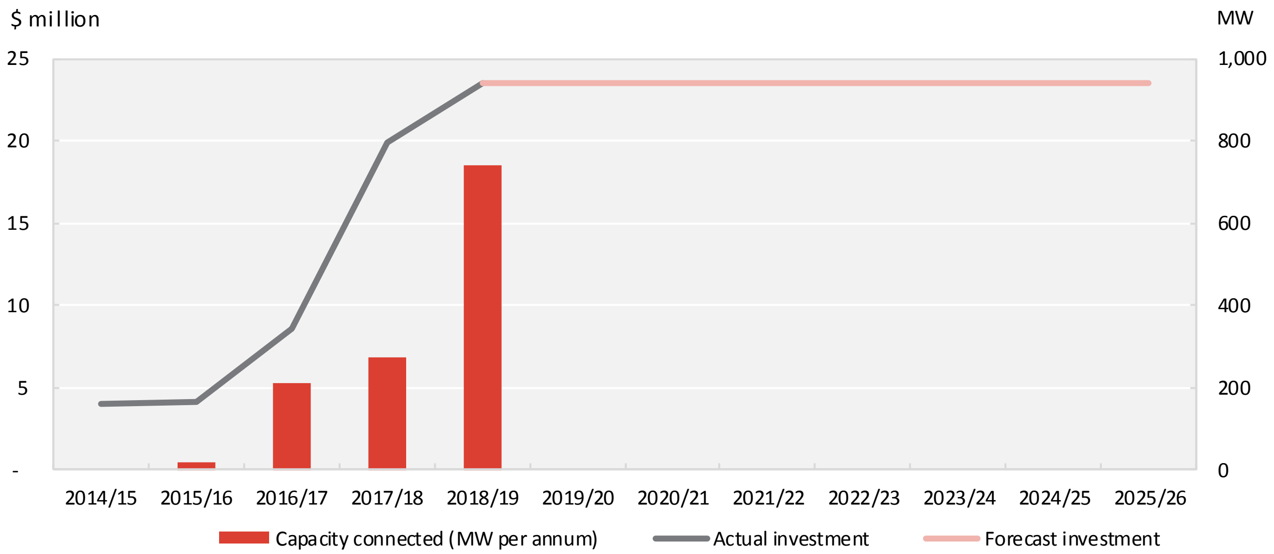
58 PAL MOD 5.01 - Connections - Jan2020 – Public.

59 PAL ATT207: Australian Energy Regulator, *Preliminary decision Powercor distribution determination 2016−20; Attachment 6 − Capital expenditure*, October 2015, p. 65.

60 PAL ATT208: Powercor, *2016–2020 Price Reset, Appendix E Capital expenditure*, April 2015, p. 111.

totals that occurred prior. We note even this is a conservative estimate as none of the renewable generations under the first renewable auction have yet connected. These connections will be 100% customer funded. Figure 5.8 shows our historical and forecast connections expenditure for embedded generation.

Figure 5.8 Historical and forecast generation expenditure



Source: Powercor

5.2.3 Forecasting contributions

We have forecast contributions, gifted assets and rebates based on the 2016/17–2018/19 average. We have not included earlier years in the average (as per our volume and unit rate forecasts) because prior to 2016, connections were regulated under the ESCV's guideline 14, under which there was a different approach for calculating these parameters compared to the current approach under Chapter 5A of the Rules.

5.2.4 Our connection investment is reviewed as part of our total capital investment program

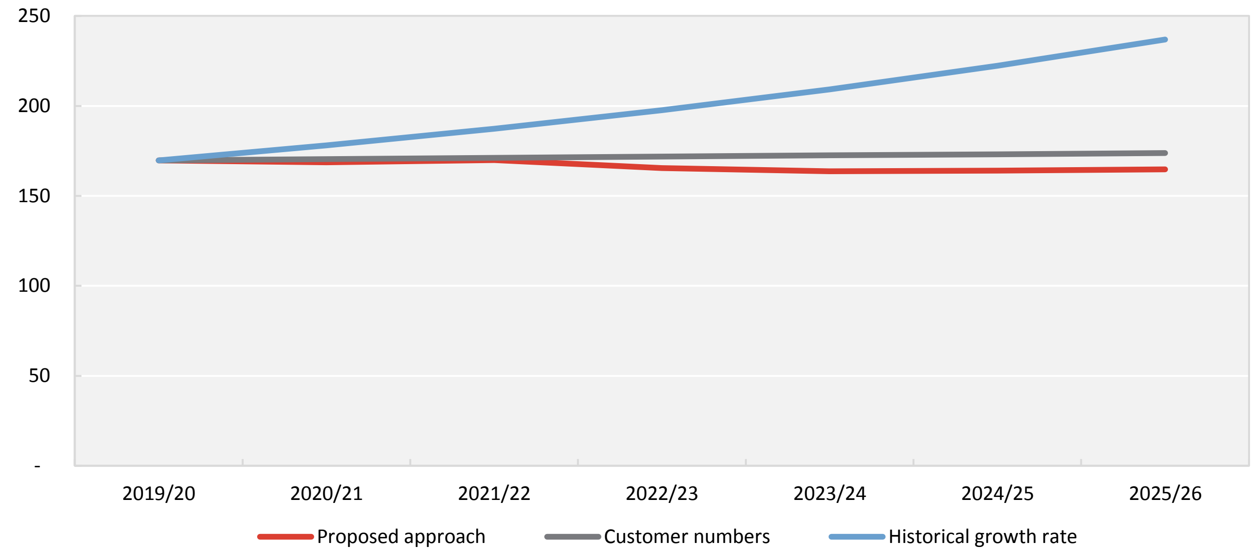
We have cross checked our forecast against alternative forecasting approaches to assess its reasonableness as outlined below:

- our first cross check was to trend forward 2015–2018 average connection growth rates. This approach would assume that historical trends continue.
- our second cross check was to apply the percentage change in customer numbers as forecast by the Centre for International Economics (**CIE**) used in forecasting operational expenditure. This approach would not address subdivisions well (i.e. when a dwelling is subdivided it would only show up as one additional customer, however, two connections are required) or commercial customers. Importantly, it would also not provide the detailed sector level forecasts we have used.

In both cross checks, low volume connections have been applied as per our actual forecast.

Figure 5.9 outlines our connections forecast under our proposed approach and the cross checks just discussed.

Figure 5.9 Forecast approach cross checks—total investment ($ million, 2021)

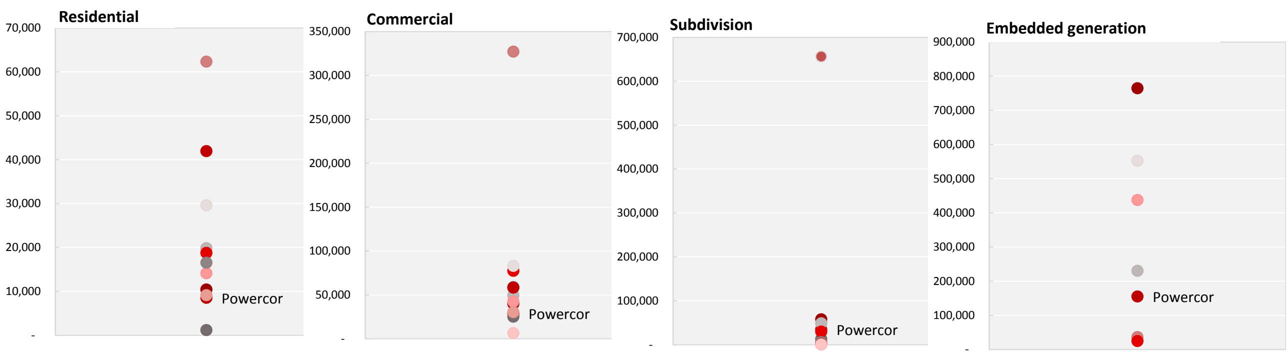


Source: Powercor

The historical growth rate approach would result in a significantly higher forecast. It is evident that ACIF do not expect the rate of growth historically experienced to continue in our network area. On balance, given the historically high growth we have experienced, we agree our forecast would be likely to lie below this cross check. Our forecast is also below that of the customer number growth cross check. Overall, these cross checks point to our forecasts as being reasonable.

We have cross checked our unit rates against those of other distributors from the Category Analysis RIN. We have taken the average rates over 2015–2017 as shown in figure 5.10.

Figure 5.10 2015–2017 average unit rates by category for each distributor



Source: Powercor, Category RIN analysis

While our rates are competitive against other distributors, this analysis demonstrates that due to network differences and different reporting methods, we do not believe the RIN information can be used to meaningfully compare unit costs.[61] The smallest range between the lowest and highest unit cost occurs in the 'residential' category, but even this has a range from $1,167 to $62,292. In 'subdivision' category, rates range from $674 to $656,037.

The efficiency of our unit rates is evident through our overall network performance. We are the most efficient distributor according to the AER's benchmarking and have the lowest rural network charges in the NEM.[62] This would not be achievable without efficient rates, given connections make up around 32% of our capital investment.[63] Further:

- we undertake competitive tenders for source material supplies and labour negotiations with our field resource suppliers have been conducted under strict governance principles.
- our unit rates are based on revealed costs—they are calculated as the average of our connections investment divided by connection volumes. Under the incentive framework, we have a continuous incentive to reduce operational and capital costs meaning our revealed costs are efficient.

Difference from draft proposal

Our connection forecast has reduced from our draft proposal that was published in February 2019 as shown in table 5.3.

Table 5.3 Comparison of forecast to draft proposal ($ million, 2021)

Proposal	Gross	Net
Draft proposal	972	400
Regulatory proposal	865	335
Difference	**-107**	**-65**

Source: Powercor

This has been primarily driven by a change in approach; from an approach driven by customer numbers to the ACIF approach. We consider this more conservative forecast is more robust and better captures the underlying drivers of connections on our network.

61 An example of different reporting is evident by comparing Powercor and United Energy. Powercor reports standard control load connections and expenditure, whereas United Energy reports standard control and alternative control load and solar connection volumes, and standard control connections expenditure.

62 PAL ATT045: Australian Energy Regulator, *Annual Benchmarking Report; Electricity distribution network service providers*, November 2018, p. 31; and distributors' distribution use of system charges for a typical customer consuming 4,200 kWh per annum.

63 Forecast over the 2021–2026 regulatory period.

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We are preparing the network to be flexible to our customers' energy needs

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6 Augmentation

Summary

Our customers are changing the way they use, store and sell electricity. Rooftop solar is already well established, and as the price of technology falls, the take-up of residential batteries is forecast to increase. Likewise, electric vehicles are expected to become more common as their affordability increases.

Our stakeholders have told us they expect us to plan for a shared energy future that meets the evolving needs of our customers and the communities they live in. For example:

- our customers want to export their excess solar back into the network so they can lower their bills, have greater energy independence and help the environment
- over 75% of our customers consider the network should be upgraded faster than is currently planned to allow for renewable energy, and they support both network investment and modernising our technology to better meet customers outcomes
- our residential customers are generally satisfied with our existing reliability and power quality levels; they are not willing to trade these off for cost savings
- our large commercial and industrial customers stressed that a reliable power supply is important, but power quality issues are more frequent and have large and wide-ranging impacts on their businesses—they want us to focus on these concerns, and to provide clear and timely communication during any incidents.

We are also experiencing continued strong demand across our network. Melbourne is forecast to become Australia's most populous city by 2030, and much of this growth will be in our western suburbs. Similarly, the Surf Coast and Geelong are growing rapidly. Our assets are already heavily loaded in these supply areas, and at a total network level, we have the highest capacity utilisation in Australia.

This growth is reflected in required upgrades to areas where rapid earth fault current limiters (**REFCLs**) have been commissioned. REFCLs are a specific bushfire technology mandated by the Victorian Government, and ongoing investment is required as more of our network assets are installed underground. We are, however, working proactively with our safety regulator to ensure we consider options to minimise any cost impacts on our customers.

Further, we have developed a plan to better support regional businesses by upgrading parts of our existing single-phase network. We have worked closely with the United Dairy Farmers of Victoria in developing this investment, and ensuring the criteria used to target this investment is sustainable.

Our overall augmentation investment forecast for the 2021–2026 regulatory period supports our customers shared energy future (including enabling our customers' solar investments), and the continued demand growth in our network supply area.

This chapter sets out how we are preparing our network to be flexible to accommodate the growing energy needs of our customers:

- in section 6.1, we outline the services our forecast investment will allow us to deliver
- in section 6.2, we provide further detail on our approach to developing our investment forecast, including the drivers of network augmentation, an overview of our planning policies, and how we use non-network and demand management solutions to manage uncertainty or avoid the need for network investment.

An overview of our forecast augmentation investment in the 2021–2026 regulatory period to support these growing energy needs is shown in table 6.1 and figure 6.1. Our augmentation forecast is consistent with our distribution annual planning report (**DAPR**), and the capital expenditure objectives, criteria and factors set out in the Rules.[64] Our forecasts have increased relative to our draft proposal, primarily due to the inclusion of REFCL compliance expenditure (which was not fully developed at the time).

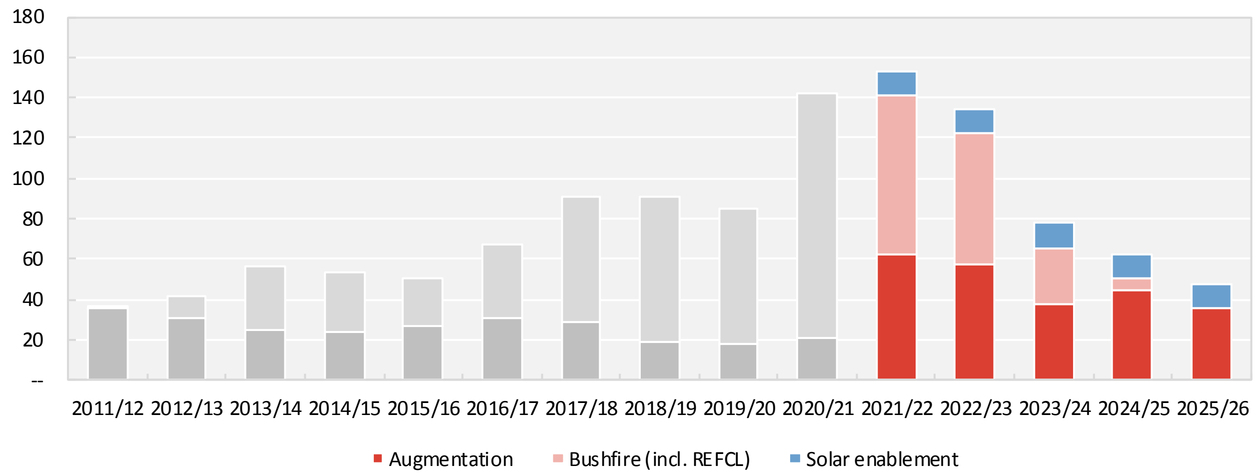
[64] PAL ATT002: Powercor, *Distribution annual planning report*, December 2019.

Table 6.1 Network investment ($ million, 2021)

Description	2016–2020	2021–2026
Augmentation investment (total)	475.1	475.2

Source: Powercor
Notes: Forecast shown includes real escalation; disposals have *not* been netted off.

Figure 6.1 Forecast investment to augment our network ($ million, 2021)



Source: Powercor
Notes: Forecast shown includes real escalation.

Our augmentation forecast is supported by a series of business cases and models for key projects or programs. These include our bushfire mitigation compliance obligations and solar enablement program, both of which are driving our increased forecast. In total, our business cases cover 74% of the augmentation investment shown in table 6.2.

Table 6.2 Summary of material business cases ($ million, 2021)

Description	Investment
Solar enablement	60.7
HV feeder forecasts	16.0
Bacchus Marsh supply area	7.7
Tarneit supply area	20.6
REFCL compliance and demand growth: Surf Coast supply area	72.9
REFCL compliance: ongoing program	60.5
REFCL compliance: tranche one, two and three sites (unspent allowance)	35.7
REFCL compliance: Corio zone substation	29.0
Upgrading regional supply	9.1
Network communications: 3G shutdown	16.2
ACMA spectrum changeover	8.4
Digital network: network devices	4.7
Total business case	**341.4**

Source: Powercor
Notes: Our network devices justification is set out in the digital network business case, included as part of our ICT chapter. Forecasts shown excludes real escalation.

6.1 What we plan to deliver

To ensure our network is flexible to our customers' growing energy needs, we commit to providing the following over the 2021–2026 regulatory period:

- enabling solar exports and renewable generation
- reinforcing our network to provide the electricity 'backbone'
- modernising our network to support customer outcomes.

6.1.1 We're enabling solar exports and renewable generation

Our customers have told us we should be taking steps to prepare for a future driven by increased solar, batteries and electric vehicles. These technologies provide opportunities for customers to lower their bills, have greater energy independence and build a sustainable future.

Solar enablement

Between now and 2026, solar capacity on our network is forecast to more than double. Solar panels are becoming more affordable over time, and are supported by the Victorian Government's initiative to subsidise the installation of solar panels on 650,000 homes and 50,000 rental properties over 10 years.

Stakeholder feedback

Since 2017, we have heard from thousands of our customers about their solar expectations. A summary of our engagement is below.

2017	2018	2019	
Initial engagement	Customer preference	Draft proposal	Options paper
Gauged customers' current use and interest in solar: • nine mini-group discussions • online survey of 600 residential and 200 small and medium business customers • seven in-depth interviews with large customers	Asked how we should prepare the network, facilitate solar and who should pay: • two opinion leaders forums • deliberative forum • online survey >800 customers • investment options forum • eight in-depth interviews with large and industrial customers	Received feedback on our proposed solar enablement approach in our draft proposal: • draft proposal forum • deep dive workshops with key industry stakeholders • in-depth interviews with large customers	Sought feedback on solar options paper, which took a more detailed look at different approaches to solar enablement: • online survey • solar online and stakeholder consultation • solar design workshop/report

A key stage of our engagement process was our solar deep dive, where stakeholders told us the approaches to enabling solar we were considering at the time were too limited in scope. As a result, we developed and consulted on an options paper.

The feedback on our options paper was clear that customers can tolerate reasonable constraints (i.e. they supported dynamic control and affordable prices), but the network must be prepared to accommodate more solar and ensure these constraints are not excessive. Our customers also viewed a 'first-in, first-served' approach to connecting solar as unfair; rather, all customers should be able to export some solar.

In our options paper, we also considered how to recover the cost of enabling solar, including:

- connection charge—an upfront charge paid by customers seeking to export solar
- 'quasi export tariff'—a reduction to the feed-in tariff received by solar customers
- tariffs—spread across all customers.

Almost two-thirds of our customers and stakeholders preferred the costs to be paid by those connecting solar. This was also the view from consumer advocates representing financially vulnerable customers. On balance, however, we opted to spread the costs among all customers, including because the benefits from our program will accrue to all. This decision is discussed in detail in our business case.

The feedback we received from our customers and stakeholders, as outlined above, has helped refine our solar enablement program. Consistent with this feedback, we will:

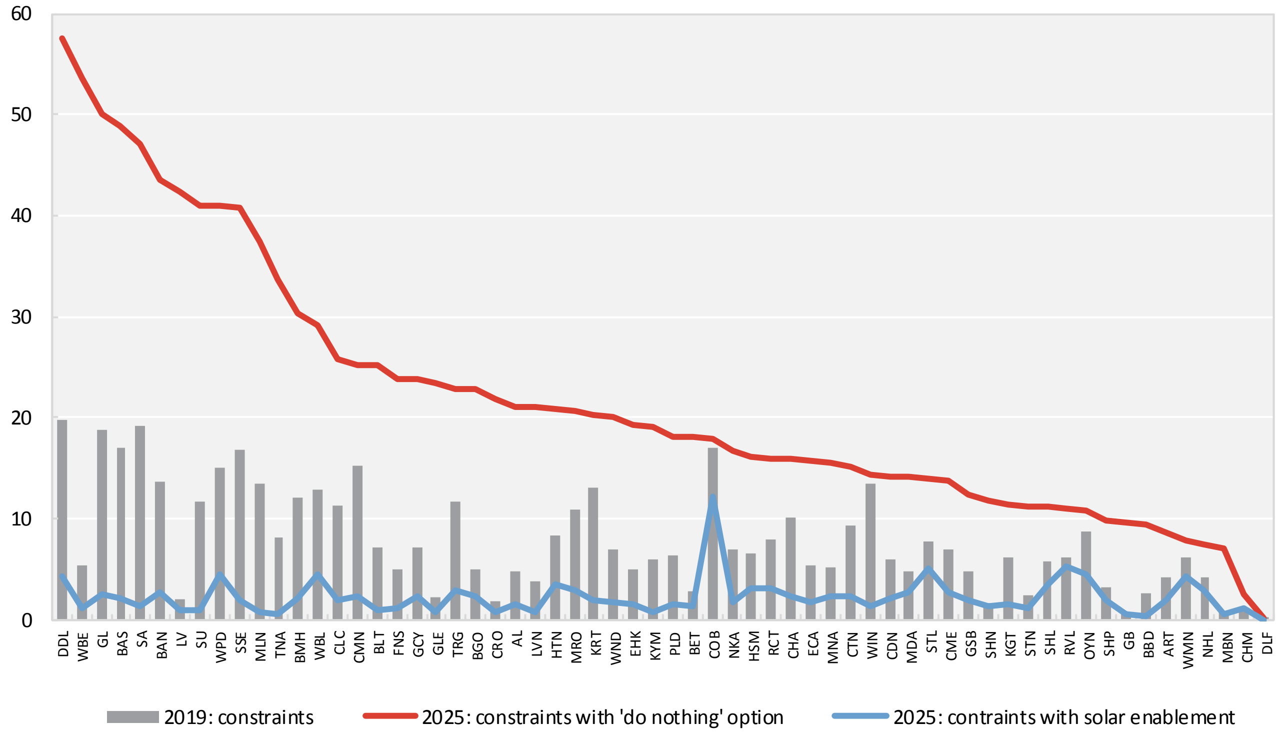
- enable all our customers to connect solar
- enable 5kVA solar systems to be available for export for most of our customers
- remove solar constraints where it is economic to do so (i.e. where the benefits to customers outweigh the costs)
- assist those customers where it is uneconomic to remove constraints to get the most out of their solar.

Our approach is also supported by extensive economic modelling. We have drawn on over 38 billion data points from our smart meters across our three networks (i.e. CitiPower, Powercor and United Energy), and considered the impact on each of our 79,000 distribution transformers.

We understand we are the only distributor to have understood the extent of network constraints for our customers to this level of detail. This has allowed us to understand the percentage of daylight hours for which solar is tripped now and in the future, as shown in figure 6.2:

- the red line indicates the time which solar is forecast to be constrained in 2025 if we undertake no action; this will result in the average customer at 47% of our zone substations experiencing constraints more than 20% of the time, and almost 15% experiencing constraints over 40% of the time
- the blue line represents the outcome after our solar enablement program and the efficient level of constraint; this will result in the average customer only experiencing solar constraints for two days of the year.

Figure 6.2 Percentage of time solar is constrained by zone substation



Source: Powercor

We have then compared the cost of removing a voltage constraint with the benefits, as measured by valuing the reduction in wholesale generation fuel costs and carbon reduction benefits from solar. These are benefits that all our customers (even those without solar) will receive. The net benefit to our customers of our program is over $76 million.

By analysing the rich data from our smart meters, we can unlock the value of our customers' solar photovoltaic (**PV**) systems using many low-cost options before we upgrade the local network. The targeted nature of our investment is also consistent with our customer and stakeholder preferences for a proportional program. In table 6.3, we compare the capital investment required under our program to remove most constraints (i.e. the distance between the red and blue lines) to the cost should we attempt to remove all constraints (i.e. the area underneath the blue line).

Table 6.3 Comparison of capital investment alternatives to remove most versus all constraints ($ million, 2021)

Description	Investment
Capital investment required under our solar enablement program	60.7
Capital investment required to remove all solar constraints	401.2

Source: Powercor
Note: Our solar enablement program also includes an IT and operating component. These are included in the business case and discussed in our ICT and operating expenditure chapters. Forecast shown excludes real escalation.

More broadly, if we do not prepare the network for the volume of solar being connected, the annual amount of constrained solar generation in 2025 across our three networks will be equivalent to the annual output of 2.4 times that produced at the Karadoc solar farm in northern Victoria.[65]

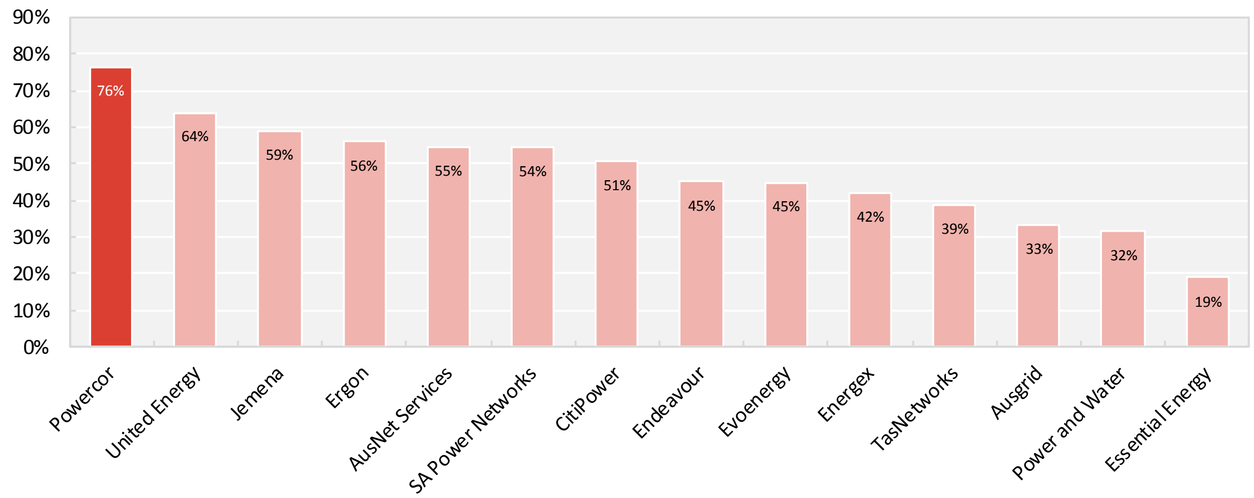
Further detail on our proposed approach to enabling solar investment on our network in the 2021–2026 regulatory period is set out in our attached solar enablement business case.[66]

6.1.2 We're reinforcing our network to provide the electricity 'backbone'

Melbourne's western suburbs and the Surf Coast area south of Geelong are developing fast, with each having significant residential, commercial and industrial load growth. Our electricity network provides the backbone that supports the ongoing growth and development of these communities.

Consistent with the capital expenditure objectives in the Rules, we must plan our network to ensure we meet forecast demand for electricity.[67] As shown in figure 6.3, we manage the most highly utilised network in Australia. This means we get the most out of our assets.

Figure 6.3 Maximum demand relative to total capacity at the zone substation level (%)



Source: AER, *Electricity distribution network service report data*, August 2019.

65 Based on the rated capacity of Karadoc, and AEMO's published capacity factor for northern Victorian solar farms.

66 PAL BUS 6.02: Powercor, *Solar Enablement*, January 2020.

67 NER, cl. 6.5.7(a).

In the 2021–2026 regulatory period, we will establish new zone substations in Torquay and Tarneit, undertake major zone substation upgrade works at Bacchus Marsh, and establish new feeders to alleviate capacity constraints.[68]

Additionally, we are looking to support our regional business customers by upgrading parts of our existing single-phase network. We have worked closely with the United Dairy Farmers of Victoria and the South West Shire in developing this investment plan.

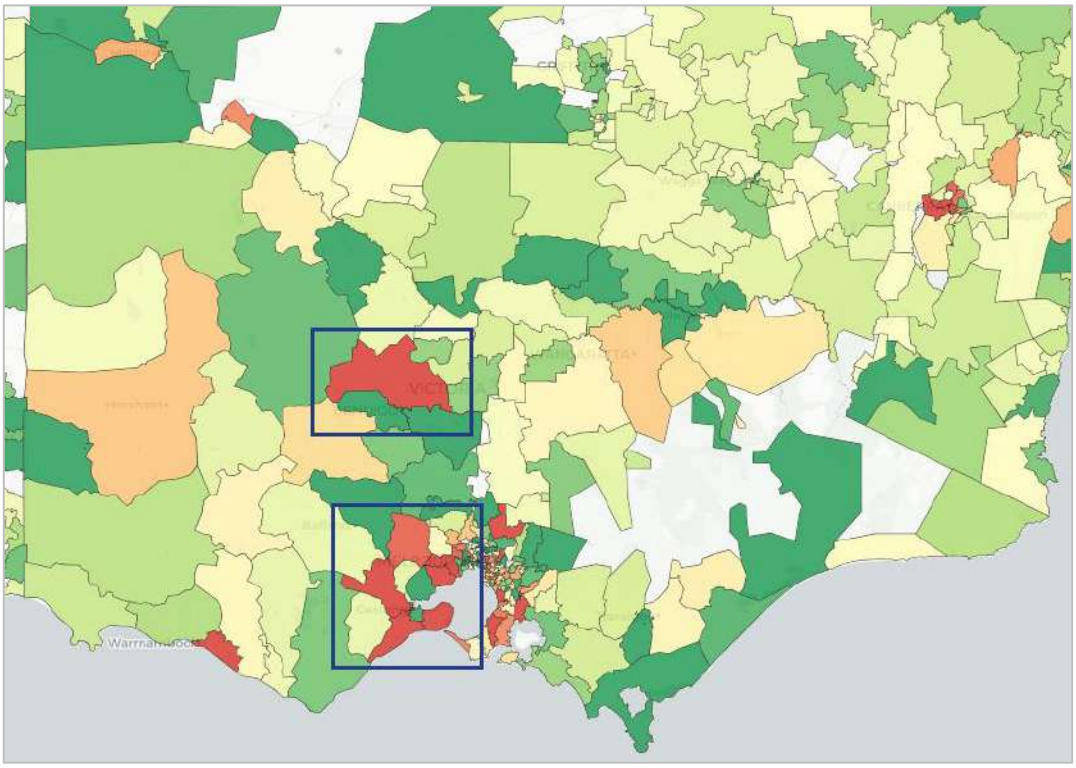
We must also invest to continue to comply with our bushfire mitigation obligations to install and operate REFCLs as our network changes.

Ensuring capacity in our distribution feeder network

Localised load growth continues to drive demand-related high voltage (**HV**) feeder investment throughout our network. As the distribution network close to our zone substations becomes established, new distribution feeders combined with capacity augmentation to the existing network are required to supply new urban fringe development areas.

Most of our forecast investment on our HV feeder network is targeted in our western and coastal high growth regions. These investments are all located in areas where existing network capacity is limited, as shown in the network opportunities map published by Australian Renewable Energy Mapping Infrastructure (**AREMI**).

Figure 6.4 AREMI network opportunity map: available distribution capacity, 2019 (MVA)



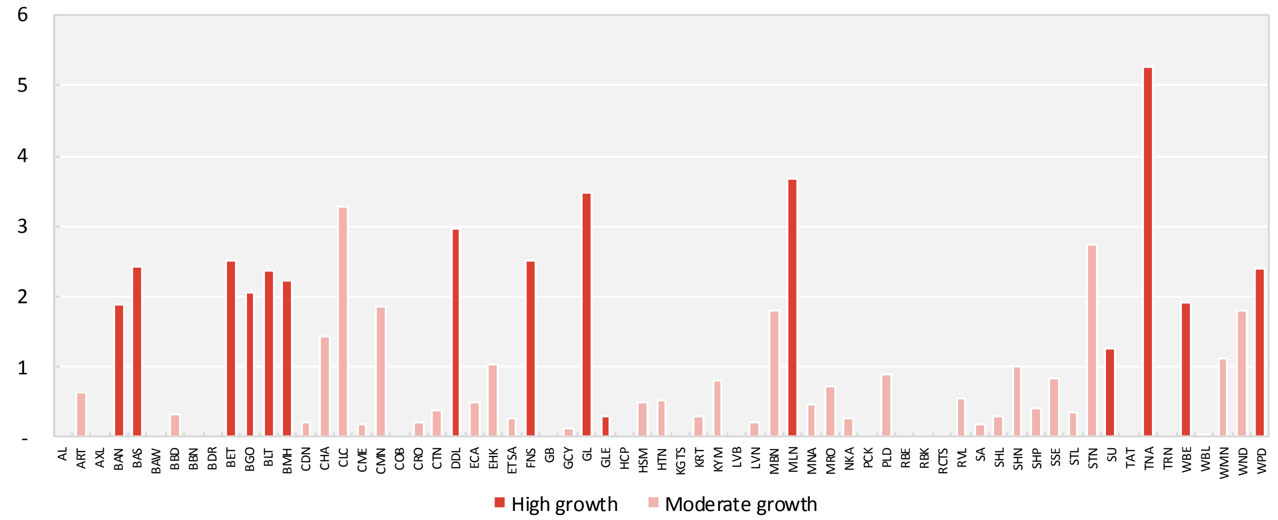
Source: AREMI

Notes: Yellow, orange and red sections represent locations where available distribution capacity is limited.

68 We will also establish a new zone substation in Ballarat West as part of our REFCL compliance program (discussed further in this document).

The concentration of our HV feeder works to these growth areas is further highlighted in figure 6.5. This shows forecast HV feeder augmentation by each zone substation for the 2021–2026 regulatory period. Almost half of our zone substations are not forecast to require feeder investment.

Figure 6.5 Forecast HV feeder augmentation by zone substation ($ million, 2021)



Source: Powercor

Our approach to forecasting feeder augmentation includes both top-down and bottom-up considerations to ensure that all macro-economic and local variables are reflected in future load growth. For example, distribution feeder upgrades are primarily required due to exceedance of thermal conductor limits that have been determined in accordance with Australian and international standards. The typical actions to address conductors that exceed thermal limits is to either replace the overhead conductor or underground cable with a higher rated conductor, upgrade an adjacent HV feeder and transfer load to it from the constrained feeder, or utilise non-network alternatives (e.g. demand response).

A summary of our total forecast augmentation investment in our HV and sub-transmission network for the 2021–2026 regulatory period is set out in table 6.4. Further assessment of key feeder projects (i.e. those greater than $1 million) that contribute to this forecast is provided in our attached HV feeder upgrades business case.[69]

Table 6.4 Distribution feeder network: total forecast investment, 2021–2026 ($ million, 2021)

Description	Investment
HV feeder and sub-transmission augmentation	73.3

Source: Powercor
Notes: Forecast shown excludes real escalation.

In December 2019, the Victorian Government proposed rental housing reforms, including a new minimum standard for all rental properties to have a fixed heater. The accompanying Regulatory Impact Statement expects this will impact on 84,442 rental properties, which will most likely install reverse cycle air-conditions.[70]

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69 PAL BUS 6.05: Powercor, *HV feeder* upgrades, January 2020.

70 PAL ATT180: Regulatory Impact Solutions, *Regulatory Impact Statement, Residential Tenancies Regulations 2020*, November 2019, pp. v, 53.

Further, the standard requires the phase out of liquefied petroleum gas (**LPG**) fuelled heaters, which are more prevalent in regional areas. We expect these reforms may result in localised load growth that may impact on low voltage (**LV**) network (e.g. feeders), particularly in areas with single wire earth return (**SWER)** lines where LPG is prevalent and the network is less able to accommodate load growth. We will continue to assess the impact of these potential reforms for the revised proposal.

Ensuring capacity in the Bacchus Marsh supply area

The Bacchus Marsh supply area, including the surrounding towns of Maddingley, Darley, Greendale, Ballan and Myrniong, are currently serviced by our two-transformer at Bacchus Marsh zone substation. Our maximum demand forecasts for this zone substation indicate an annual average compound growth rate of 4.9%.

We apply a probabilistic approach to planning all our demand-driven investment decisions. Consistent with this approach, the quantity and value of energy at risk is a critical parameter in assessing prospective network investment or other action in response to an emerging constraint. The forecast increase in demand at our Bacchus Marsh zone substation, coupled with the prevailing load characteristics at the site, means the energy at risk of not being supplied should one of the existing transformers fail is relatively high. For example, after load transfers are established, a shortfall in capacity of approximately 20 MVA is forecast for 2026 (or loss of supply for approximately 6,700 customers).

We assessed several options to ensure we continue to provide a reliable supply of electricity in the Bacchus Marsh area. The most efficient option is to install an additional transformer at our Bacchus Marsh zone substation, and undertake corresponding re-configuration works.

Table 6.5 summarises the forecast investment required in the 2021–2026 regulatory period to support the preferred option. The full justification for these works, including our options analysis, is provided in the attached Bacchus Marsh supply area business case and investment model.[71]

Table 6.5 Bacchus Marsh supply area: total forecast investment, 2021–2026 ($ million, 2021)

Description	Investment
Bacchus Marsh zone substation and distribution works	7.7

Source: Powercor
Notes: Forecast shown excludes real escalation.

Ensuring capacity in the Tarneit supply area

As noted previously, significant residential, commercial and industrial development has occurred in our distribution territory in the western suburbs of Melbourne. This growth is expected to continue, with demand in Derrimut, Mount Cottrell, Tarneit, Ravenhall, Wyndham Vale and Truganina creating overloading issues on our existing Werribee and Truganina zone substations that supply these areas.

Consistent with our DAPR forecasts, load at our Werribee zone substation currently exceeds its N-1 rating before any contingency transfers. New distribution feeders in 2019 and 2020 will transfer some of this load to our Truganina zone substation, but the forecast load will still exceed the station N rating in 2024. Likewise, load is above the N-1 rating at our Truganina zone substation. This follows feeder offloads from our Werribee and Laverton zone substations in 2019 and 2020, and the planned installation of a third transformer in 2021.

[71] PAL BUS 6.04: Powercor, *Bacchus Marsh supply area*, January 2020.

We assessed the combined energy at risk at our Werribee and Truganina zone substations, and considered several options to address the identified need of maintaining a reliable supply of electricity for new residential growth and development in the Tarneit supply area. These options address the identified need to varying extents, and as such, the preferred option is that which maximises the net economic benefits.

The most efficient network option is to establish a new Tarneit zone substation in 2025. This option was compared to the estimated cost of a non-network solution that would result in the energy at risk remaining at the same level as that forecast in the year immediately prior to the proposed commissioning date of the Tarneit zone substation. This comparison was based on the observed cost of non-network solutions, and an independent comparative analysis of other distributors experience.

A summary of the investment required to support the establishment of a new Tarneit zone substation is set out in table 6.6. This investment has been reduced since our draft proposal as we have further refined the scope of required works. The full justification for this project, including our options analysis, is provided in our attached Tarneit supply area business case and investment model.[72]

Table 6.6 Tarneit supply area: total forecast investment, 2021–2026 ($ million, 2021)

Description	Investment
Establish new Tarneit supply area	20.6

Source: Powercor
Notes: Forecast shown excludes real escalation.

Maintaining supply quality

The capital expenditure objectives require that we comply with all applicable regulatory obligations or requirements associated with the provision of standard control services. This includes our quality of supply obligations set out in the Electricity Distribution Code.[73]

Stakeholder feedback

Our stakeholder engagement program found that, generally, our residential customers are satisfied with reliability and power quality, and want existing levels maintained. For example, 56% of residents and 54% of small business customers gave a score greater than nine out of ten when asked if they were satisfied with their existing power quality.

For large commercial and industrial customers, having a reliable power supply is important, but power quality is their biggest concern as these issues are more frequent and have large and wide-ranging impacts on their businesses. Accordingly, they want us to prioritise fixing these issues and to provide clear and timely communication during any incidents.

Our forecast investment required to maintain supply quality in our LV network over the 2021–2026 regulatory period includes the following:

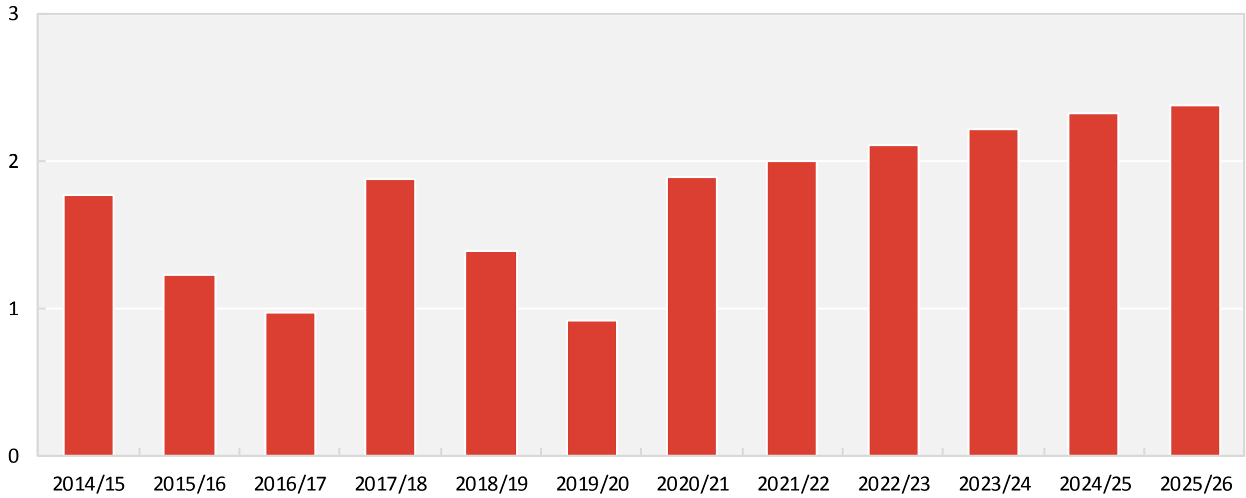
- re-balancing phases to prevent single phase overloads
- upgrading conductors to prevent voltage drop or allow additional load to be connected
- replacing transformers that are overloaded (proactively rather than replacing under faults)
- changing conductors or transformers to address harmonics, flicker or other power quality problems.

[72] PAL BUS 6.03: Powercor, *Tarneit supply area*, January 2020; PAL MOD 6.06 - TRT supply area - Jan2020 – Public.

[73] PAL ATT 178: Essential Services Commission, *Electricity Distribution Code*, January 2020, clause 4.

We have forecast our supply quality investment based on observed supply quality interventions. As shown in figure 6.6, this investment trends upwards over the 2021–2026 regulatory period in line with load growth expectations for existing and new customers.

Figure 6.6 Supply quality investment ($ million, 2021)



Source: Powercor
Notes: Forecast shown excludes real escalation.

We have also ensured the investment proposed for maintaining supply quality does not overlap with our proposed solar enablement program. Our existing solar policy, whereby we prevent solar export capability if the connection would create a material voltage constraint, ensures that solar driven investment is not included in our historical expenditure or forecasts based on historical expenditure.

Looking forward, although it is conceivable that supply quality and solar enablement works will be required at the same location—meaning only one investment is needed—the potential for any material overlap is limited. Our supply quality program will address an average of 65 issues per annum across our population of 79,000 transformers. In turn, our solar enablement program will address 205 sites on average each year. The drivers for these works are fundamentally different, and coupled with the low volumes relative to the total population, the chances of these programs overlapping is minimal.

Our total forecast supply quality investment in the 2021–2026 regulatory period is set out in table 6.7.

Table 6.7 Maintaining supply quality: total forecast investment, 2021–2026 ($ million, 2021)

Description	Investment
LV network augmentation: maintaining supply quality	11.0

Source: Powercor
Notes: Forecast shown excludes real escalation.

Ensuring capacity in the Surf Coast supply area

Our Waurn Ponds zone substation supplies electricity to almost 36,000 customers in southern Geelong, as well as customers in the Surf Coast towns of Torquay, Jan Juc, Anglesea and Lorne.

Our maximum demand forecasts indicate an annual average compound growth rate of 3.0% in the Waurn Ponds supply area up to 2028. This is supported by independent forecasts from the Surf Coast Shire, that expects annual population growth of over 3.3% in 2021–2026 for the Torquay area.[74]

This demand growth is primarily due to high population increases in both the Surf Coast and Armstrong Creek areas. Further, significant new loads are expected as the development of 22,000 new land lots in the Armstrong Creek urban growth corridor proceeds.

We need to maintain a reliable supply of electricity to customers in the Waurn Ponds supply area as the level of energy at risk continues to grow over time. As set out in our attached Surf Coast supply area business case and cost model, our preferred option to address the identified need is to establish a new Torquay zone substation.[75]

Establishing a new Torquay zone substation will also support the least-cost compliance option for meeting our regulatory obligations to install REFCLs at our Waurn Ponds zone substation by April 2023.

A summary of the investment required to establish our Torquay zone substation, and to ensure REFCL protection across the Surf Coast supply area, is set out in table 6.8.

Table 6.8 Surf Coast supply area: total forecast investment, 2021–2026 ($ million, 2021)

Description	Investment
Torquay zone substation: zone substation works	25.3
Torquay zone substation: REFCL works	10.5
Waurn Ponds zone substation: REFCL works	11.3
Network hardening to support REFCLs	25.7
Total	**72.9**

Source: Powercor
Note: The Torquay zone substation works are set out in our augmentation investment model, whereas the REFCL compliance works are included in our bushfire investment model. Forecast shown excludes real escalation.

Maintaining REFCL-protection in our network

In our replacement expenditure chapter, we discussed how we will continue to provide a safe network that mitigates bushfire risk. This recognised that we operate a distribution network in one of the most bushfire prone locations in the world.

A key component of our bushfire mitigation program is our requirement to ensure specific zone substations in our network are supported by REFCL technology.[76] This compliance obligation is set out in the *Electricity Safety (Bushfire Mitigation) Regulations 2013* (**Amended Bushfire Mitigation Regulations**).

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74 PAL ATT242: Surf Coast Shire, *Economic Insights*, 2018.

75 PAL BUS 6.01: Powercor, *Surf Coast supply area*, January 2020; PAL MOD 6.11 - Surf coast options analysis - Jan2020 – Public.

Our augmentation investment over the 2021–2026 regulatory period includes three key components of our REFCL program:

- works required to ensure capacity in the Surf Coast supply area (as discussed previously)
- works required to install REFCLs approved in our tranche three contingent project application
- works required to ensure we maintain compliance with our REFCL obligations as our network evolves.

A summary of the required investment for meeting our REFCL compliance obligations is set out in table 6.9. Our tranche three sites and ongoing program are expanded on below.

Table 6.9 Maintaining REFCL-protection in our network: total forecast investment, 2021–2026 ($ million, 2021)

Description	Investment
REFCL compliance: Surf Coast supply area (REFCL works only)	47.5
REFCL compliance: tranche three sites	35.5
REFCL compliance: Corio zone substation	29.0
REFCL compliance: ongoing program	60.5
Total	**172.5**

Source: Powercor
Note: The Surf Coast supply costs outlined above are consistent with those included in table 6.8 (excluding the Torquay zone substation works), and are presented here for completeness. Forecast shown excludes real escalation.

REFCL compliance: tranche three sites

We have now installed REFCLs at nine zone substations throughout our network, and must install REFCLs at a further 13 zone substations by 2023. The cost of installing REFCLs at these remaining sites has mostly been approved in our three contingent project applications.[77]

Consistent with the Rules, however, our regulatory proposal includes the REFCL expenditure from our contingent project applications that will be incurred in the 2021–2026 regulatory period. The contingent project mechanism was designed to accommodate large projects that traverse regulatory periods.[78] Therefore, any unspent capital expenditure approved by the AER through its contingent project decisions is included in our regulatory proposal for the 2021–2026 regulatory period.

In January 2020, the AER published its final decision for our tranche three contingent project application. This decision rejected our forecast capital investment required to install REFCLs at our Corio zone substation. The basis of the AER's decision was their expectation of changes to our legislated regulatory obligations that have not yet been made by the Victorian Government.

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76 REFCLs reduce the risk of a fallen line or vegetation contact causing a fire start by operating like a giant safety switch—when a powerline comes into contact with vegetation or the ground, they stop dangerous current levels almost instantaneously.

77 Our Waurn Ponds zone substation was not included in our tranche three application due to its complexity, and the nature of the proposed solution—as set out in our Surf Coast supply area business case, we have considered our Waurn Ponds compliance obligations in conjunction with our proposed establishment of a new zone substation at Torquay (resulting in a more efficient solution).

78 See, for example, NER, cl. 6.5.7(f).

At the time of finalising our regulatory proposal, the AER's final decision for our tranche three REFCL program was not available. As such, the expenditure included in our regulatory proposal reflects what we proposed to the AER as part of our contingent project application.

We have, however, presented the investment associated with our Corio zone substation in a separate line in our consolidate bushfire model. Notwithstanding the AER's final decision, and our commitment to seeking the least-cost solutions to meeting our REFCL obligations, in the absence of any legislative change the installation of REFCLs at our Corio zone substation will continue as planned. Our proposed Corio zone substation expenditure is supported by our attached business case.[79]

We will update our REFCL compliance forecast to reflect the AER's final decision in our revised regulatory proposal.

REFCL compliance: ongoing program

The Amended Bushfire Mitigation Regulations include details of the need for each polyphase electric line originating from selected zone substations to meet specified capacity requirements. The specified capacity requirements can only be met through using REFCL technology—namely, by migrating our existing systems to a resonant earthed network through the installation of a ground fault neutraliser (**GFN**).

The number of GFNs required at any zone substation is driven by a range of factors, including total system capacitance. Total system capacitance is itself a function of overhead line and underground cable length (noting the capacitance of underground cable is an order of magnitude more than 40 times that of overhead lines).

A single GFN can support the required performance standards to a maximum total system capacitance of between 81–108A. This range has been developed with input from the REFCL technical working group (**TWG**), and based on both ours and AusNet Services' observed REFCL experience to date.

As our network grows—in particular, as more underground cables are installed in residential and industrial subdivisions, or as part of our ongoing bushfire mitigation programs—several of these sites will require additional GFNs and corresponding capital works to ensure we continue to meet the specified capacity requirements. The assessment of which sites will require additional works is based on capacitance forecasts. These sites are set out in table 6.10.

79 PAL BUS 6.10: Powercor, *Corio zone substation REFCL*, January 2020.

Table 6.10 REFCL compliance: summary of ongoing program, total forecast investment 2021–2026 ($ million, 2021)

Description	Investment
Colac zone substation: new REFCL and feeder rearrangements	3.2
Bendigo Terminal Station: new isolation transformer and feeder rearrangement	2.5
Ballarat West zone substation: to be established	31.0
Bendigo zone substation: feeder rearrangement	1.2
Castlemaine zone substation: new REFCL	2.8
Eaglehawk zone substation: new REFCL and 3rd transformer	7.7
Winchelsea zone substation: new REFCL and 3rd transformer	8.7
Gisborne zone substation: new REFCL	3.3
Total	**60.5**

Source: Powercor
Notes: Forecast shown excludes real escalation.

The development of our capacitance forecasts, and the scope and location of our required REFCL upgrades (including alternative options), are set out in our attached REFCL upgrade business case.[80]

Supporting regional business customers

Supplying electricity to regional Victorians is core to our values and what we do. We are proud to support regional businesses throughout our network.

However, through our recent stakeholder engagement program it became clear that regional infrastructure located in dairy farm intensive regions is not meeting our customers' needs and that targeted regional investment will result in significant economic and community benefits. In particular, our existing low capacity powerlines are hampering their ability to build their communities through expanding their operations.

80 PAL BUS 6.08: Powercor, *REFCL ongoing compliance*, January 2020.

Stakeholder feedback

In April 2019, we met with customers and community leaders in Warrnambool. They expressed strong support for us considering the broader benefits of upgrading electricity distribution infrastructure and highlighted any investment to improve supply will have the following benefits:[81]

- increase milk production for the region, the state and the country
- increase dairy industry confidence
- assist in keeping dairy farming operating, and enable people to stay in business
- achieve a lower cost of production
- have a positive flow on effect for those who are suppliers to dairy farms.

Since the forum, we also received multiple letters supporting the view that the current electricity supply is hindering potential new investment, including the following:

> *'I am the owner of a steel fabrication/engineering workshop located [in Tyrendarra]… With my current power supply, I feel that the business has reached its maximum capacity in machinery and employees. To sum up I am at a financial standstill due to my lack of acceptable power supply.'*

> *'Rabobank is an agriculture-based organisation and we would like to express our support for this type of infrastructure upgrade… Some collateral benefits of this project could be to encourage conversion of low intensity farm land to (highly intensive) dairying, further development of milk processing capacity, and both farming and milk processing service providers expansion.'*

We have since worked with the United Dairyfarmers of Victoria (**UDV**), Great South Coast Food and Fibre Council and Dairy Australia to understand the complex issues facing rural communities. Together with them, we have identified four key areas that would significantly benefit from upgrading single-phase to three-phase supply.

Under the existing regulatory framework, major capital investments must be subject to a regulatory investment test for distribution (**RIT-D**) to demonstrate the benefits of any investment outweigh the costs. The typical market benefit classes considered in a RIT-D focus on the value of unserved energy and changes to customers' costs. The outcome of this process is that rural customers generally receive lower levels of service than urban customers, primarily due to lower customer density resulting in higher costs to service and relatively low unserved energy.

The typical application of the RIT-D framework, however, does not account for the differing value of electricity to customers and the economy at the local level. While it is impracticable to achieve service level parity between rural and urban groups, a better balance can be achieved by broadening the benefits assessment to include the economic impact of regional business.

As set out in our attached regional supply upgrades business case, the benefits of our proposed investment will exceed the costs if the broader economic impacts of enhancing capacity—such as more regional employment and growth—are considered.[82] Dairy Australia and the UDV have provided studies demonstrating the economic benefits of investment in the dairy industry, and the flow-on impacts to surrounding townships. For example, the value of the dairy industry in 2016–2017 was $3.6 billion, and Victoria accounted for 64% of milk production in Australia.[83]

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81 PAL ATT240: Woolcott, *Warrnambool Stakeholder Roundtable Report, Report prepared for Powercor*, April 2019.

82 PAL BUS 6.09: Powercor, *Upgrading regional supply*, January 2020.

83 See: http://www.agriculture.gov.au/abares/research-topics/surveys/dairy

Our business case also sets out criteria for defining the circumstances in which a consideration of broader economic benefits is appropriate. This acknowledges concerns from some stakeholders about the potential for consideration of these benefits to lead to over-investment. Our criteria include that the proposed investments:

- be targeted at supporting regional communities
- have demonstrated stakeholder support
- not exceed 1% of revenue over the regulatory period
- support customers that have a strong reliance on electricity
- support customers that generate important or significant value/goods/services to Victorians, and those benefits are received by a large proportion of customers.

The capital investment to upgrade regional supply in four locations in our network is set out in table 6.11. Supporting regional communities is a critical component in our 'social' licence to operate a rural distribution network, and consistent with the capital expenditure factors set out in the Rules.[84]

Table 6.11 Supporting regional business customers: total forecast investment 2021–2026 ($ million, 2021)

Description	Investment
Upgrading regional supply: Tyrendarra	3.4
Upgrading regional supply: Strathdownie	2.5
Upgrading regional supply: Cape Bridgewater	1.8
Upgrading regional supply: Gorae West	1.4
Total	**9.1**

Source: Powercor
Notes: Forecast shown excludes real escalation.

6.1.3 Modernising our network to support customer outcomes

Since 2009, our customers have funded a significant investment in smart meters. We are leveraging this investment to lean more on technology and data than ever before to provide electricity through smarter network decisions. This facilitates data-driven investments, and helps us better meet customer outcomes at the lowest cost.

As discussed below, the investment required to support smarter network decisions in the 2021–2026 regulatory period includes modernising our communications infrastructure and enabling a digital network.

Modernising our network communications infrastructure

The safe and efficient operation of our network relies heavily on communicating with our infrastructure over networks controlled by independent third parties. Our access to these communications networks is changing over the 2021–2026 regulatory period.

84 NER, cl. 6.5.7(e)(5A).

Network communications: 3G shutdown

Telstra's 3G communications network will be progressively retired over the 2021–2026 regulatory period to make way for 5G technology. When the 3G communications network is retired, we will lose our capability to remotely communicate with devices used to operate, control and monitor the network, and collect metering data. For example, we remotely communicate with our network devices to perform important functions such as:

- regulatory compliance—vary the operating mode of assets in bushfire areas, and collect information from smart meters installed at customers' premises
- outage detection—used to detect the location of an outage, resulting in shorter outage times
- remote switching—used to switch electricity around our network to minimise the effect of outages
- remote sensing—remotely monitor the condition/operation of assets and power quality.

We investigated several alternatives to ensure we continue to provide these functions. These options included using other providers' 3G networks, targeted refurbishment of specific assets, upgrading our existing 3G control boxes and access points, and developing our own communications network using our advanced metering infrastructure.

The options considered were compared to the impact on customers of not investing (i.e. a 'do-nothing' option, whereby we lose all reliability, efficiency and compliance benefits). For the reasons set out in our attached business case and investment model, the preferred option is to upgrade our existing infrastructure to be 4G and 5G compatible.[85] A summary of the investment required to support this option is set out in table 6.12.

Table 6.12 3G telecommunications shutdown: total forecast investment, 2021–2026 ($ million, 2021)

Description	Investment
Network communications: 3G shutdown	16.2

Source: Powercor
Notes: Forecast shown excludes real escalation.

ACMA spectrum changeover

To support communications in low customer density rural areas where optical fibre infrastructure does not exist, we have long operated a private microwave radio network. This radio network supports critical communications to our zone substations for monitoring, data capture and remote control functions.

Our radio network operates over frequency bands that are licensed by the Australian Communications and Media Authority (**ACMA**). ACMA has provided notice that we will lose some of our existing frequency licences in the 2021–2026 regulatory period to make way for new technologies that require an increase in bandwidth (such as 5G cellular.

Similar to our response to the shutdown of Telstra's 3G communications network, we investigated several alternatives to ensure we continue to comply with regulations, protect our assets, and maintain the safety and reliability of our network when these frequency bands are reallocated.

The preferred option is to upgrade our existing radio components to operate at a new, higher frequency. The only available bandwidth that meets our requirements, as advised by ACMA, also requires additional

[85] PAL BUS 6.06: Powercor, *3G shutdown*, January 2020.

communications towers to support the higher frequency (i.e. higher frequencies do not travel as far as lower frequency signals).

Further supporting material for this investment is set out in our radio network upgrades business case and investment model.[86] A summary of the required investment is set out in table 6.13.

Table 6.13 ACMA spectrum changeover: total forecast investment, 2021–2026 ($ million, 2021)

Description	Investment
ACMA spectrum changeover	8.4

Source: Powercor
Notes: Forecast shown excludes real escalation.

Supporting a digital network

Distribution networks across the world are currently going through some of their largest transformations in history. These transformations are being driven by changing customer requirements, including increased participation in new demand management programs, and the expected take-up of EVs and batteries.

During the 2021–2026 regulatory period, we will implement more advanced technology capabilities through our digital network initiative. This will allow us to make smarter and more dynamic network decisions to improve safety outcomes and support customers as they take up new innovations, all while keeping the costs of running the network down.

Most of the investment required to develop a digital network is included in our IT program. This program, however, also includes a network element—specifically, the targeted rollout of network devices at contestable metered sites or distribution transformers—that is captured in the network communications component of our augmentation forecast. These devices will provide real-time consumption and power quality information.

The full justification for this program, including the corresponding options analysis, is set out in our digital network business case. Table 6.14 shows the investment required for the network component of this program.

Table 6.14 Digital network: network device investment, 2021–2026 ($ million, 2021)

Description	Investment
Digital network: network devices	4.7

Source: Powercor
Notes: Forecast shown excludes real escalation.

6.2 Our forecasting approach

This section outlines how we plan our network to ensure our customers can continue to choose how they use electricity. This includes an overview of the following:

- the drivers of our augmentation investment
- our planning policies, and how these manage risk

86 PAL BUS 6.07: Powercor, *Network communications spectrum changeover*, January 2020; PAL MOD 6.12 - ACMA spectrum - Jan2020 – Public.

- how non-network solutions are assessed through cost-benefit analysis to ensure we only invest where and when it's needed.

Our augmentation forecasts are consolidated in our attached augmentation, bushfire and communications models.[87]

6.2.1 Our augmentation investment is driven by both demand and non-demand factors

Our forecast augmentation investment includes both demand driven and non-demand driven projects.

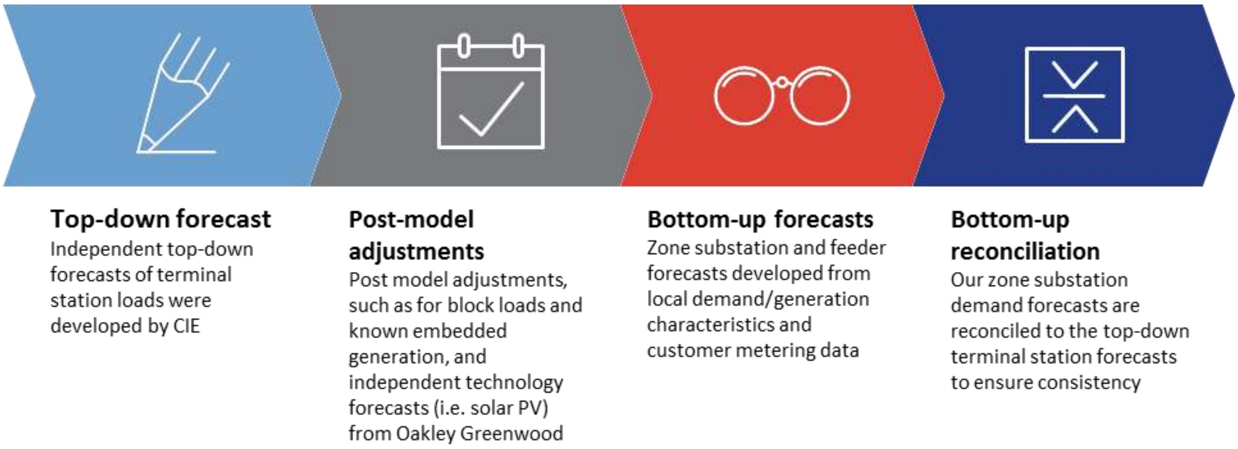
Demand-driven augmentation investments

Localised maximum demand on our network is a key driver of our forecast augmentation investment. Where demand is expected to exceed the capacity of our network in a particular area, we look to intervene to ensure we continue to maintain a reliable supply of electricity to our customers. These interventions, which also have regard to risk (as discussed in section 6.2.2) may include reconfiguring our network, additional infrastructure, or implementing non-network solutions.

Our approach to forecasting demand for the 2021–2026 regulatory period combines our own detailed local knowledge with independent economic analysis by the Centre for Independent Economics (**CIE**). A summary of our approach is set out in figure 6.7.

A more detailed discussion is provided in our demand forecasting attachment.[88]

Figure 6.7 Overview of our demand forecasting approach



Source: Powercor

Non-demand driven augmentation investment

We also plan our network to manage non-demand driven factors. These include compliance obligations, considering the impact of future fault currents, voltage levels and voltage quality, and whether these factors are forecast to exceed the levels stipulated by regulatory obligations.

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87 PAL MOD 6.01 - Augex - Jan2020 – Public; PAL MOD 6.09 - Bushfire safety - Jan2020 – Public; PAL MOD 6.04 - Network comms - Jan2020 – Public.

88 PAL APP03: Powercor, *Maximum demand and customer numbers*, January 2020.

Fault levels

A fault is an event where an abnormally high current occurs as a result of a short circuit somewhere in our network.

We estimate prospective fault current to ensure it is within allowable limits of the electrical equipment installed, and to select and set protective devices that can detect a fault condition. Devices such as circuit breakers, automatic circuit reclosers, sectionalisers and fuses can act to break the fault current to protect the electrical plant, and avoid significant and sustained outages as a result of plant damage.

Fault level mitigation programs are increasingly required on our network as the level of embedded generation being directly connected to our network increases.

Voltage levels

We are required to maintain customer voltages within specified thresholds set out in the Electricity Distribution Code.[89]

Voltage levels are important for the operation of all electrical equipment, including home appliances with electric motors or compressors (e.g. washing machines and refrigerators), and farming and other industrial equipment. These appliances are manufactured to operate within certain voltage threshold ranges.

Voltage levels are affected by a number of factors, including the export of electricity onto our network, impedance of transmission and distribution network equipment, length of sub-transmission and distribution feeders, implementation of REFCLs, and load and capacitors in our network.

Quality of supply (to other network users)

The connection of embedded generators or large industrial customers to our network may result in a reduction of the quality of supply experienced by other customers on our network. In these circumstances, we may invest to ensure we maintain quality of supply across our network.

These investments are typically undertaken following system studies as part of the new customer connection process.

Compliance with regulatory obligations

As outlined previously, we are subject to prescriptive legislative requirements regarding the installation and operation of our REFCL infrastructure. Complying with these obligations requires ongoing investment, and is particularly driven by the installation of additional underground cables.

6.2.2 Our planning processes prioritise key network risks

We apply a probabilistic approach to planning all our demand-driven investment decisions. This approach involves estimating the probability of an outage occurring within the peak period, and determining the energy at risk of not being supplied.

The energy at risk of not being supplied is assigned a monetary value based on how much customers value reliability. The value of customer reliability (**VCR**) we apply is that determined by AEMO, adjusted for inflation.[90]

89 PAL ATT 178: Essential Services Commission, Electricity Distribution Code, January 2020, clause 4.2.

90 The AER is now required to develop an estimate of the VCR, and published new VCRs on 18 December 2019. These VCRs, however, have not been reflected in this regulatory proposal.

Our augmentation forecast only includes capital works where the cost of mitigating a forecast constraint is lower than the monetised value of energy at risk, and a lower cost demand side solution is not feasible.

Ultimately, probabilistic network planning aims to ensure that an economic balance is struck between:

- the cost of providing additional network capacity to remove constraints
- the cost of having some exposure to loading levels beyond the network's capability.

In other words, we recognise that given extreme loading conditions may occur for only a few hours in each year, it may be uneconomic to provide additional capacity to cover the possibility that an outage of an item of network plant may occur under these conditions.

6.2.3 We continue to seek non-network solutions

We consider and adopt non-network solutions, including demand management, to avoid or defer the need to invest in network augmentation when it is efficient. We seek non-network solutions through our DAPR and public forums on our entire demand-driven augmentation program, when undertaking a RIT-D for major augmentation works, and through our demand side engagement register.

For the 2018–2019 summer period, we also offered payments to customers throughout the Bellarine Peninsula, and parts of the Surf Coast, to increase the temperature on their air conditioners during critical peak periods. Based on the feedback from our deliberative stakeholder forums—our customers were clear that we should not directly control their appliances—participation was entirely voluntary.

The aim of this demand response initiative is to defer the need to undertake around $4 million of powerline upgrades to increase their capacity. Customers in these areas experienced major supply interruptions during the 2017–2018 summer period. Demand management may offer an affordable and sustainable alternative to expanding our network.

We are committed to continuing our engagement with the broader industry and our customers to seek further opportunities for growing non-network solutions in the 2021–2026 regulatory period.

6.2.4 Our unit cost forecasts are based on recent historical costs

We forecast costs for capital projects based on recent historical costs for efficiently delivered projects of similar scope, size and geographic locations. As the most cost-efficient distributor in Australia, based on AER benchmarking, we consider our historical costs provide a reasonable basis for forecasting future investment requirements.

We also use rates from service providers that are derived from periodic tendering where available and appropriate. This includes our materials cost forecasts, which are procured through stringent contracting arrangements.

We adjust costs for forecast growth in real input prices over time, such as labour, materials and contracted services.

6.2.5 We will deliver our augmentation program with support from our resource partners

Our labour force is structured to provide flexibility in managing labour resources. This allows us to deliver our total capital program, including the forecast increases in investment over the 2021–2026 regulatory period.

Further detail on our labour contract types are included in section 4.2 of our replacement investment chapter. For example, these labour types include our internal workforce, and our reliance on local service area agents and resource partners.

7 Information and communication technology

Summary

Information and communications technology (**ICT**) is integral to a modern electricity distribution network. Our customers view reliability, affordability and the privacy of their data as top priorities, and maintaining the currency of our ICT systems allows us to continue to deliver these services effectively and affordably. Our recurrent ICT investment will focus on:

- cyber security: we will enhance our cyber-security capabilities to maintain pace with an evolving threat landscape. This includes developing security on access and control of the supervisory control and data acquisition (**SCADA**) system, which is critical to ensuring we maintain security of the distribution system and provide reliable electricity to customers.
- market systems: we will prudently deploy version upgrades to maintain support for our systems which manage the delivery of data to the market, including AEMO, retailers and our customers.
- network management systems: we will maintain the currency of the systems that directly manage our network. Maintaining currency of these systems is critical to maintaining the safe, reliable, secure and efficient delivery of network services.
- cloud infrastructure: as part of our continued search for the most efficient approach to delivering IT services, we will migrate some of our existing on-premise IT infrastructure to cloud hosting and deliver cost savings for customers.

We will also maintain the currency of other systems, including our facilities security, business intelligence and business warehousing, telephony and enterprise market systems.

Further, our ICT investments will enable us to improve customer experience, respond to changes in the energy market, drive improvements to our network planning and operations, and meet new compliance obligations. This non-recurrent ICT investment will focus on:

- digital network: we will develop a smarter network that responds to the transformation underway in the energy market, ensuring we can run the network safely and more efficiently
- customer enablement: this program will improve the way customers access information, saving them time and effort through unifying customer portals and using artificial intelligence to ensure customers receive better services when they contact us
- SAP upgrade: we will upgrade to the latest SAP product once vendor support on our existing product ends
- five minute settlement: under rule changes determined by the AEMC, we must enhance existing systems to provide five minute interval data for market settlement (by December 2022)
- intelligent engineering: we will improve data accuracy to improve employee and community safety.

At the heart of our success at delivering major ICT projects is a prudent approach to adopting technology that provides tangible benefits to our customers. Throughout the 2021–2026 regulatory period, we will continue to invest in our ICT to help provide safe, secure, reliable and affordable services to our customers.

Technological change is occurring at an accelerated pace and is being impacted by a number of trends. This includes an explosion in available data, the ability to realise new insights through analytics, emerging cyber security threats, rising customer expectations on service provision, more automation and increasingly complex ICT environments. These trends provide opportunities and challenges for us and our customers in the 2021–2026 regulatory period.

Our proposed ICT investment over the 2021–2026 regulatory period is set out in figure 7.1.[91] This includes both recurrent and non-recurrent investments, consistent with the AER's ICT expenditure guideline.[92]

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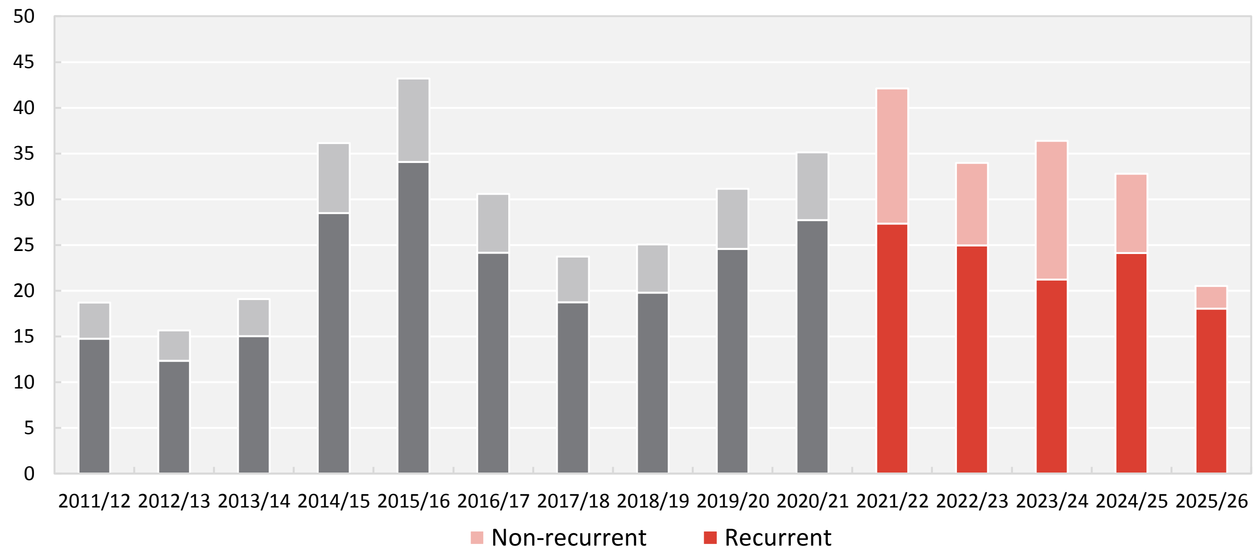
91 This investment is in alignment with the capital expenditure objectives as stipulated by cl 6.5.7(a) of the Rules and addressing the capital expenditure criteria as specified in cl 6.5.7(c) of the Rules.

92 While some of our initiatives have both recurrent and non-recurrent investment (as outlined in detail in the respective business cases), below we have outlined them by their primary driver.

Figure 7.1 Forecast ICT investment ($ million, 2021)



Source: Powercor
Note: Forecast shown includes real escalation. The peak in expenditure in 2021/22 is a result of large investments to comply with our five-minute settlement obligations.

Table 7.1 also provides our forecast ICT investment for the 2021–2026 regulatory period.

Table 7.1 Forecast ICT investment ($ million, 2021)

Description	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Total	42.1	34.0	36.4	32.8	20.5	165.8

Source: Powercor
Note: Forecast shown includes real escalation.

7.1 What we plan to deliver

ICT ensures we can efficiently and affordably provide a safe and reliable network, improve the way we deliver services to customers, and support the delivery of new innovations. This section describes those ICT initiatives we plan to deliver in the 2021–2026 regulatory period, and our track-record in delivering ICT projects.

7.1.1 Recurrent investment

Recurrent ICT is investment related to maintaining existing ICT services, functionalities, capability and/or market benefits. Our recurrent investment remains in line with history, reflecting our business-as-usual requirements. Table 7.2 provides our proposed recurrent ICT investment by project.

Table 7.2 Summary of proposed ICT capital investment for recurrent projects ($ million, 2021)

Project	Investment
Cyber security	19.3
Cloud infrastructure	25.2
Market systems	6.5
Network management systems	19.9
Business intelligence and business warehousing	2.5
Device replacement	13.6
Enterprise management systems	10.4
Telephony	4.0
Facilities security	6.0
General compliance	4.6
Total	**112.0**

Source: Powercor
Notes: Forecast shown excludes real escalation.

We will ensure our ICT systems remain secure from cyber threats

We are a key part of Australia's critical infrastructure and deliver services essential for everyday life, such as manufacturing, transport, communications, health and finance.

The technologies we use to provide this critical infrastructure are connected and accessible in ways that were not possible even just 10 years ago. In this context, although technology has provided us with many benefits, it exposes us to risks, including corruption to our systems and files from computer viruses, sensitive data being stolen through hacking, and entities attempting to take control of the network. For example, in 2015 in Ukraine, a cyber attack resulted in power being lost to more than 230,000 residents.

The Australian Cyber Security Centre also ranks the energy sector in the top four industries most at risk of a cyber-security threat.[93] Similarly, the *Security of Critical Infrastructure Act 2018* (Cth) was developed in recognition of the evolving national security risks to infrastructure including electricity assets from sabotage, espionage and coercion.

Given the potential consequences of a security breach, we must ensure the security of our IT and systems keep pace with new threats. This is consistent with our stakeholder feedback, where our customers viewed keeping our network data and their privacy secure as a core value proposition.

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93 PAL ATT177: Australian Government – Australian Signals Directorate, *ACSC Threat Report*, October 2017.

Our assessment of a range of options for managing these growing risks found that our current security systems can be extended to more effectively prevent cyber security attacks and incidents. This includes refreshing our security for SCADA access to ensure we retain proper authorisations to control the network.

Further information on our options analysis, such as costings for each alternative and our risk monetisation assessment, is available in our cyber security business case.[94]

We will transition to cloud

In the 2016–2020 regulatory period, we embarked on a strategy to migrate core applications supported by on-premise ICT infrastructure to cloud hosting. This arrangement gave us flexibility to choose the right technologies, and to alter services or providers in response to changing business requirements.

With the maturing of cloud offerings, we now have an opportunity to further migrate existing on-premise infrastructure to cloud. A flexible cloud-based approach will lower costs to customers, and provide the following advantages:

- adaptability to changing business requirements, because we can change services more readily
- scalability to ensure we can manage our costs, because cloud services are based on capacity and use
- reduced reliance on vendor support, because we can more easily switch service providers
- avoiding the need to manage maintenance or replacement.

The full justification and risk-monetisation for our proposed migration is available in our cloud infrastructure business case.[95]

We will maintain and support our existing systems

The majority of our ICT investment is to maintain the capabilities of our existing suite of technologies. In the 2021–2026 regulatory period, these investments include:

- market systems—our market systems provide centralised storage and validation of meter reading data, manage market communications and manage customer requests in accordance with our compliance requirements. Technical currency is essential to ensure continued vendor support and compatibility with the integrated software. We have proposed a prudent approach by adopting every second system release, which delivers savings to customers.[96]
- network management system—these comprise core operational systems such as GIS, outage management system and distribution management system, which are used to manage network operations. Retaining the currency of these systems is essential to continue monitoring and operating the network in real-time, 24 hours a day, as needed to maintain a safe, reliable and secure network.[97]
- business intelligence and business warehousing (**BI/BW**)—we will implement a low cost central data repository to improve the speed and effectiveness of reporting and decision-making, for example in relation to network management, customer service and compliance reporting. The single central data repository will

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94 PAL BUS 7.04: Powercor, *Cyber security*, January 2020.

95 PAL BUS 7.10: Powercor, *Cloud infrastructure,* January 2020.

96 PAL BUS 7.06: Powercor, *Market Systems*, January 2020.

97 PAL BUS 7.07: Powercor, *Intelligent engineering*, January 2020.

be shared between CitiPower, Powercor and United Energy, consolidating four data warehouses to one, resulting in a near 40% saving across the three businesses.[98]

- devices—we have a highly mobile workforce which needs access to applications to perform their roles and communicate reliably. As a result, our workforce uses computers, phones, mobile tablets, and other devices. These devices require replacement on a periodic basis as the asset reaches the end of its expected life to maintain the current level of operational performance. These devices are essential for retaining the $20 million productivity savings realised through our Click program, which would be lost if our devices are not properly maintained.[99]
- enterprise management systems—ensure we maintain currency of applications relating to asset investment planning, corporate services, customer platforms, data management and field services. These are reaching end of life or will no longer meet business requirements due to changes in technology, customer requirements or cyber security threats.[100]
- telephony—maintain currency of our telephony systems used for contact centre, corporate and control room functions with incremental improvements to the customer experience.[101]
- facilities security—enhance the IT systems underpinning facility security (i.e. CCTV cameras, gates and keys) and maintain the processes that integrate site access with authorisation records in place of manual processes, to prevent safety issues from unauthorised access.[102]
- general compliance—we operate under rules and obligations that impact on the data and support our ICT systems must provide. These obligations are periodically amended. This project investment is in line with current levels and is needed for smaller periodical updates (as opposed to known material structural changes, such as metering contestability or five-minute settlement).[103]

Each of the projects listed above have an associated business case, which provides more detail on the proposed investment, costs, and alternative solutions explored. These proposed measures are all designed to ensure we continue to provide a safe, reliable and secure network for customers while ensuring value and affordability. Our risk monetisation analysis demonstrates the cost to maintain system currency is efficient relative to the high value of risk which would occur if systems are not maintained.

7.1.2 Non-recurrent investment

Our forecast non-recurrent investment is shown in table 7.3. These investments include technologies to unlock new benefits for customers, as well as that required to comply with new regulatory obligations.

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98 PAL BUS 7.03: Powercor, *BI BW*, January 2020.

99 PAL BUS 7.12: Powercor, *Device replacement*, January 2020.

100 PAL BUS 7.11: Powercor, *EMS*, January 2020.

101 PAL BUS 7.13: Powercor, *Telephony*, January 2020.

102 PAL BUS 8.07: Powercor, *Facilities Security*, January 2020.

103 PAL BUS 7.14: Powercor, *General Compliance*, January 2020.

Table 7.3 Summary of proposed ICT capital investment for non-recurrent projects ($ million, 2021)

Project	Investment
Digital network	11.1
Customer enablement	8.1
Intelligent engineering	4.4
SAP upgrade	12.9
Five minute settlement	8.9
Solar enablement	2.6
Total	**48.0**

Source: Powercor
Notes: Forecast shown excludes real escalation

We will develop a more digital network

The energy landscape is changing rapidly with increasing penetration of household solar, batteries, EVs. However, altered usage needs and the reverse power flows created by these innovations will make it more difficult to predict and manage power flows on the network.

In the 2021–2026 regulatory period, we will extend our network devices to customers without smart meters, implement data platforms and conduct new analytics to improve network visibility. Over time, this will allow us to manage the network efficiently in near real-time, through better forecasting, monitoring, diagnosis and eventually through automation. This will enhance network safety, efficiency and reduce network augmentation to lower customer bills over the long term.

Specifically, our digital network initiatives include:

- promoting the uptake of new technologies—by allowing us to monitor the impact of increasing EV penetration on demand and optimise charging away from peak times, we will facilitate the uptake of EVs while mitigating the risk of excess demand at peak times (preventing the need for augmentation)
- optimising load control of customer appliances—optimising existing hot water load control and enabling new load control programs (e.g. air conditioners, pool pumps, fridges), including through utilising excess solar in the middle of the day
- enhancing cost reflective pricing—analysing meter data to construct more effective time-of-use tariffs or demand response to reduce peak demand and improve overall utilisation of the distribution network
- improving the equity of energy usage—identifying sites with bypass connections to reduce theft and monitoring variable unmetered supply to ensure energy usage is allocated fairly between customers
- proactively managing asset failures—develop greater predictive capabilities for asset condition to better determine when assets will fail, resulting in less network investment
- avoiding overblown fuses—improving phase balancing, which will allow greater asset utilisation and avoid replacing blown fuses

- looking after vulnerable customers—more accurate mapping of customers to the network to ensure we keep more life support customers connected during outages and provide more accurate communications to customers on planned outages
- keeping customers safe—improving the way we identify loss of neutral at customers' homes, which can pose major safety issues of electric shocks if left unchecked.

We commissioned Jacobs to quantify the benefits of three different implementation options to ensure we provide the maximum benefit to customers. These options involved no additional investment, solely rolling out technology platforms, and rolling out both technology and extending network visibility through additional network devices. Jacobs determined that rolling out both technology and extending our device coverage would provide the largest net benefit to customers.

More information is available in our digital network business case.[104]

We will improve customer enablement

The improvement in customer service across industries means our customers expect to interact with us in a variety of ways, including through better online experiences. We understand customers want simple and customised responses, and for us to proactively provide information.

Stakeholder feedback

We have heard from our customers that they want a streamlined and accessible experience online. When surveyed, 58% of customers stated they were interested in accessing real-time data and just under three-quarters of residents would use this data to seek rebates or savings.

> *'I look at my accounts now and a year ago to see if usage is the same as last year. That is all I do. I feel a bit in the dark at the moment.'*

Many participants in our forums also requested that we invest in a 'one-stop-shop'.

Over the 2016–2020 regulatory period, we steadily improved our customer-facing applications. In the 2021–2026 regulatory period we will continue our journey to provide services that align with our customers' needs and expectations—for example, our customer enablement program includes:

- consolidating our online portals to provide an integrated customer experience such as through a single username, password and interface (i.e. a one-stop-shop)
- improving the capabilities of myEnergy to provide data analytics and customer notifications
- improving the effectiveness of SMS notifications during outages and introducing notifications on the efficiency of customers' rooftop solar output and exports
- providing customers with access to more frequent usage data on a mobile application to better inform their energy choices.

As detailed in our attached business case, our customers will benefit from our customer enablement program through saved time and effort in accessing their information and receiving more targeted notifications about outages and their solar rooftop systems.[105]

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104 PAL BUS 7.08: Powercor, *Digital Network*, January 2020.

105 PAL BUS 7.02: Powercor, *Customer Enablement*, January 2020.

We will establish intelligent engineering capabilities

Our customers view network safety as a core and unquestionable priority.

Our intelligent engineering business case sets out how we will leverage new technology to improve the safety of our employees and the community, and more effectively manage the network.[106] For example, we will improve the accuracy 'dial before you dig' to deliver improved safety outcomes and protect network assets when our customers perform works.

Improving our data management capabilities will also decrease network design planning timeframes, as more accurate data will allow us to automate processes, reduce network planning and design costs.

We will perform a major upgrade to SAP S/4 HANA

We use a SAP system to perform essential business functions that underpin our financial reporting, support our customer connections processes and help maintain the safety of our network by capturing the maintenance activities conducted on our assets. Our existing SAP platform which will reach the end of its lifecycle and end of vendor support by 2025.

We analysed five different options for managing the risks associated with an 'unsupported' system, and determined the lowest cost and risk path involved upgrading SAP (as opposed to moving to new vendors or a third party support model). This analysis was informed by recent experiences with third party support arrangements, which increased complexity and costs in the longer term.

Further, integrating IT systems between the three distribution networks we own and operate—CitiPower, Powercor and United Energy—rather than maintaining them as separate systems, will provide synergies that lower the costs by $5.4 million.

The full justification for our SAP S/4 HANA upgrade is available in our attached SAP business case.[107]

We will meet new five-minute settlement compliance requirements

We must enhance our ICT systems to comply with changes to the Rules that require us to provide five-minute interval data for NEM settlement. In particular, any smart meter installed after December 2018 must have the capability to record five-minute interval energy data by December 2022.

Our current ICT systems do not have the capacity to provide five-minute interval energy data to the market. As detailed in our five-minute settlement business case, a bottom-up review of the required system changes found that system changes will be required to collect and validate five minute interval data.[108]

We will enable more solar

As outlined in section 6.1.1, we are preparing our network to enable more solar. An important component to ensure this occurs at the least-cost for customers is developing a dynamic voltage management system—an IT system to remotely and dynamically manage network voltages at the zone substation level of our network.

We are investing to develop this system, and more information is available in our solar enablement business case.[109]

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106 PAL BUS 7.07: Powercor, *Intelligent Engineering*, January 2020.

107 PAL BUS 7.01: Powercor, *SAP*, January 2020.

108 PAL BUS 7.09: Powercor, *5 minute settlement*, January 2020.

109 PAL BUS 6.02: Powercor, *Solar enablement*, January 2020.

7.1.3 Delivering projects through a rigorous and flexible approach

We have a strong track record of delivering large IT projects within scope, time and budget. Examples include implementing systems to support the rollout of smart meters across our network, upgrading systems to enable meter contestability, establishing 'Click' to optimise field service delivery, and implementing our online portal eConnect to streamline the way we connect customers. As a result, we are highly adaptable to changes in systems and processes, allowing us to realise the benefits of ICT programs swiftly.

A key way we are able to deliver large projects while minimising associated projects risks and costs is through vendor support and third party contractors. We can ramp up resources when a project's workload peaks, before returning labour to normal levels as the project scales down. This is especially advantageous in delivering large-scale IT projects, which require greater and lesser resources at different stages of a project. In this way we ensure we appropriately resource projects to achieve our milestones effectively and efficiently.

We also provide appropriate project oversight through a rigorous governance process. This helps to ensure key strategic decisions about the business remain in-house. Projects are coordinated through our internal project management office to ensure we have the right mix of internal and external skills. Our resources are managed at both the project and program level to ensure we take interdependencies into account.

Further information is available in our attached IT delivery plan.[110]

7.2 Our forecasting approach

We only invest in ICT when there is a clear benefit to customers. Our forecasting approach to support this aim is described below:

- our starting point was to assess our existing ICT capabilities and the services they provide to our customers. As part of this, we identified whether elements of our existing ecosystem were no longer providing value to customers.
- we examined synergy opportunities to integrate our ICT systems with United Energy, weighing up the risks to systems and business processes from such integration activities. This built upon work in the 2016–2020 regulatory period, where we aligned our vegetation management reporting system, ICT issue resolution systems and telephony systems. In the 2021–2026 regulatory period, we identified synergy opportunities where system alignment will reduce overall project implementation costs for our customers as we upgrade SAP and consolidate BI/BW data storage.
- we considered whether existing systems can withstand maturing and emerging cyber-security threats. Unless we maintain and continue to develop our cyber security tools, they quickly become irrelevant and ineffective, risking the security of the network operations and data privacy.
- we then forecast the efficient level of investment needed to retain the effectiveness and security of existing capabilities.

Overall, we found that most of our existing technologies will continue to provide benefits to our customers in the 2021–2026 regulatory period. This reflects the prudency of our investment choices in the past and that our ICT ecosystem has been carefully designed over time.

We also considered whether new technologies can address key business requirements including to enhance safety, ensure compliance and improve service delivery to customers at least cost. In addition to developing

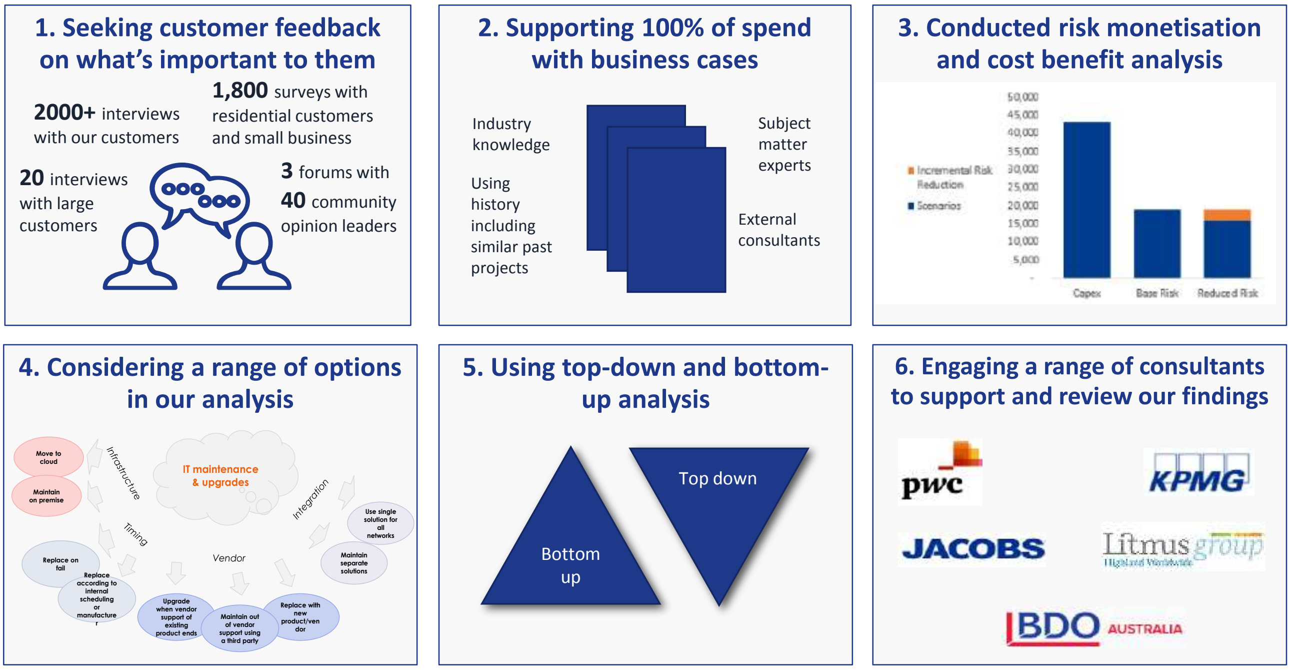
[110] PAL ATT007: Powercor, *IT deliverability plan*, January 2020.

robust business cases for these projects, we tested these new projects with customers and other stakeholders, to ensure we prioritised our investments in areas customers most value.

7.2.1 Ensuring a cost-efficient approach

We ensured efficiency was at the cornerstone of developing our forecast through a number of measures as described in figure 7.2.

Figure 7.2 Developing forecasts



Source: Powercor

We weighed the costs and benefits at a project level to determine the true value of a project for customers, including for recommended options and non-recommended options. We determined expenditure at a granular level, applying unit costs based on past projects of a similar scale and complexity, using external labour rates and known vendor costs, and seeking external validation.[111]

Where we have identified projects that are driven by customer benefits but have potential expenditure savings that may be realised over the 2016–2020 regulatory period, we have taken these savings into account. In the case of operating expenditure savings, we consider these projects contribute toward the 0.5% pre-emptive productivity adjustment. As an efficiency frontier network, we have already achieved considerable productivity improvements through investment in new technologies and changes in operating practices and have limited capacity to achieve the 0.5% productivity adjustment through business as usual activities during the 2021–2026 regulatory period. In the case of capital savings, we have netted these from our 2021–2026 forecasts.

We also subjected the portfolio to a top-down challenge. We engaged PwC Australia (**PwC**) to assess whether individual projects could be better prioritised or delivered more efficiently in order to optimise value for our customers.

111 PAL ATT153: Powercor, *IT external labour rates*, March 2019.

7.2.2 We take a risk-based approach to assessing projects

To inform our ICT investments, we have started analysing projects through a risk-based framework to help quantify whether a projects risk outweighs its expected cost. In this way we are able to holistically determine the potential costs involved in an investment decision for customers. This work is based on AER guidelines and internal analysis to monetise network risk, but is adapted for the ICT landscape.

Under this approach we use a deterministic view (i.e. we consider the risks at a point in time, instead of considering how risk changes over the years under a probabilistic approach). This is due to a lack of available data to reliably predict the probability of ICT asset failure over time both internally and in the broader ICT community. However, this work provides strong foundations for developing our approach over time.

Approach

Our ICT risk monetisation approach is described as follows:

- quantify the risks involved in a 'do nothing' case of not investing to maintain vendor support, and instead using an unsupported system
- quantify the risks of the proposed and alternative options, including business as usual options
- compare the 'do nothing' case to the proposed and alternative options to determine the highest risk-mitigation option.

We have considered two primary risks—ICT risk and business risk—and have not exhaustively covered every risk. More information these two risk categories is discussed below.

Risks quantified in our ICT risk monetisation

ICT risk considers the immediate risks to ICT teams and users of a system. They are captured through assessing the probability and impact of the following risk types:

- outage the direct financial consequences incurred by an ICT team in the event of an outage, including the lost productivity from staff being unable to use systems and any remediation or workaround activities required.
- cyber security breach: the direct financial consequences for an ICT team in the event of a breach.
- suitability: the consequences of continuing to use an existing ICT asset that is unable to meet the future needs of the underlying business process it supports. This is driven by changes in process requirements over time, and is typically due to external factors (e.g. introduction of a GST).
- system sustainability: the consequences from not undertaking required maintenance activities, such as internal maintenance or patches to ensure the continued health and stability of ICT assets. This impacts on the health and performance of a system, resulting in lost productivity.

The financial consequences of these ICT risks are valued in terms of lost employee utilisation and rectification costs. Lost employee utilisation is measured according to the estimated employee hours impacted. Rectification costs assess the number of employee or specialist hours, associated fixed costs with identifying and resolving a risk event, implementing workaround activities and activities to prevent the issue occurring again.

Business risk considers the wider risks encountered by the business and the community as follows:

- reliability: the reliability consequence to the network arising from the failure of an ICT asset, as measured via the applicable VCR.
- compliance: the direct financial consequences associated with regulatory or legislative compliance breach arising as a result of failure of an ICT asset. This can be measured by compliance penalties and associated legal or regulatory costs.
- customer experience: the direct financial consequence associated with adverse impacts to customer interactions arising as a result of a failure of an ICT asset. For example, this can be valued according to the value of customer time.
- bushfire and safety risk: the safety and health consequence to workers and the wider public, including loss arising from an injury or fatality, as well as property damage arising from the failure of an ICT asset.
- financial risk: the direct financial consequence (or loss) not taken into account in any of the above areas of consequence.

To quantify the ICT and business risks described above, we use the following data sources:

- existing IT data (e.g. outage data, frequency of patches, number of compliance updates required each year)
- other relevant network data (e.g. connection requests, de/energisations)
- documented assumptions where data is not available.

A key source of data has been an incident at United Energy, which reveals how inadequate investment in ICT systems can affect customers and the network. A case study of this experience is provided in figure 7.3.

Figure 7.3 Case study: United Energy supercluster incident

Prior to acquisition, United Energy had a heavily outsourced model

- It consisted of a small management team, overseeing a large number of vendors and contractors
- As a result, a number of key strategic decisions were effectively outsourced

This led to a number of issues, including the 'Supercluster'

An unsuitable vendor solution was implemented, which had:

1. Shared storage, providing a single point of failure and creating poor reliability
2. Low performance of the Disaster Recovery solution
3. Limited connectivity options due to architecture

This had a number of issues impacting customer:

- Suspended meter reading, risking regulatory compliance
- Billing delays impacting ~$12M revenue
- Inability to access work schedules and service orders
- Unavailability of life support reporting
- High call times as front of house call staff had to default to manual service requests
- Extended customer outage times, and delays in Live Line and Tree Clearing

Source: Powercor

8 Non-network

Summary

Non-network capital expenditure includes property, fleet, tools and equipment. This is necessary to support the operation of the network and deliver a safe and reliable service for our customers. In the 2021–2026 regulatory period, we propose to:

- upgrade five of our depots to ensure we can continue to deliver a reliable network at efficient cost
- increase the security of our critical assets in response to increasing security risks
- ensure the compliance of our network sites with relevant building codes
- maintain our fleet, tools and equipment capability to support network operations.

Over the 2021–2026 regulatory reset period, the population of Melbourne and the surrounding regions is predicted to experience strong growth. To meet the associated increased demand on our network, we will expand or build depots on new sites to ensure our footprint best services our network. We will also maintain good asset management practices by upgrading existing depots so that we can continue to provide a reliable service to our customers.

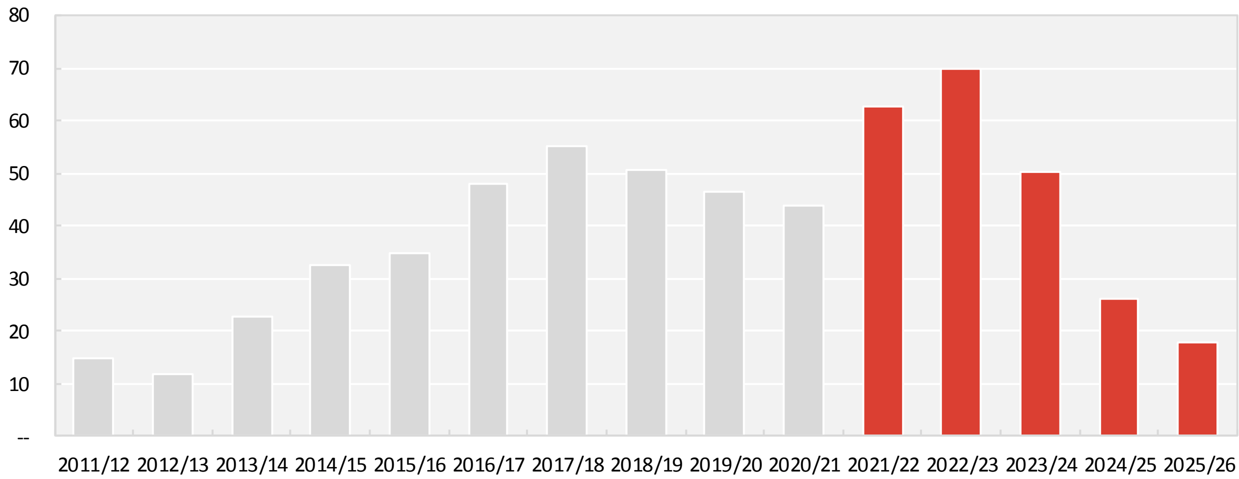
Following a review conducted by Bellrock Group using a risk-based approach, we are increasing the security of our critical assets including zone substations, distribution assets and depots in response to increasing concerns of theft and other unauthorised access.

Our fleet of vehicles are essential to ensuring we can continue to carry out our work efficiently and reliably. Our forecast fleet investment for the 2021–2026 regulatory period reflect our historical level. This is appropriate because our investment drivers are expected to remain unchanged.

Our forecast for non-network is made up of property, fleet, and tools and equipment. We take a prudent approach to non-network investment, adjusting our activities over time to ensure we maintain a balanced portfolio.

The profile of our historical and forecast non-network investment is shown in figure 8.1.

Figure 8.1 Non-network capital investment ($ million, 2021)



Source: Powercor
Notes: Forecast shown includes real escalation.

The profile of our non-network investment is driven by the need to prioritise works to ensure we meet network safety and compliance obligations, and complete depot works efficiently, accounting for project interdependencies. As shown in table 8.1, our total forecast is lower than our historical investment.

Table 8.1 Non-network investment ($ million, 2021)

Description	2016–2020	2021–2026
Total investment	244.1	227.5

Source: Powercor
Notes: Forecast shown includes real escalation.

8.1 What we plan to deliver

Over the 2021–2026 regulatory period, the population of Melbourne and the surrounding regions is predicted to experience strong growth. To meet the associated increased demand on our network, we will:

- upgrade, and build depots on new sites to maintain operating standards and network reliability
- ensure our buildings are complaint with safety and health obligations and support workplace diversity
- ensure our buildings are secure and compliant with relevant building standards
- maintain our fleet and general equipment.

Our forecast for each year of the regulatory period is outlined in table 8.2.

Table 8.2 Forecast capital investment for property, fleet and tools and equipment ($ million, 2021)

Description	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Property	30.6	37.3	27.4	13.4	5.3	114.0
Fleet	29.5	29.5	19.7	9.8	9.8	98.4
Tools and equipment	2.4	2.4	2.4	2.4	2.4	12.2
Total	**62.5**	**69.2**	**49.6**	**25.7**	**17.5**	**224.6**

Source: Powercor
Notes: Forecast shown excludes real escalation.

8.1.1 We will ensure our property investment remains in line with industry standards

We have identified a number of depots that require essential works over the 2021–2026 regulatory period. These investments are supported by separate business cases attached with our regulatory proposal.[112] These works and their associated drivers are summarised below:

- we will purchase a replacement site and construct a new depot in Warrnambool. The existing depot layout is not fit for purpose with sub-optimal traffic flow and ineffective material storage, which can impact the safety of employees working onsite. The close proximity to the sea and resulting salt corrosion is doubling the deterioration of materials, fleet and buildings at the current site. In addition, we will improve facilities to meet increasing workplace diversity.

112 PAL BUS 8.03: Powercor, *Warrnambool*, January 2020; PAL BUS 8.02: Powercor, *Echuca*, January 2020; PAL BUS 8.05: Powercor, *Bendigo*, January 2020; PAL BUS 8.04: Powercor, *Brooklyn*, January 2020; PAL BUS 8.06: Powercor, *Ballarat*, January 2020.

- we will construct a new depot in Echuca following the purchase of land in 2019. This site no longer meets the operational and diversity needs for employees and equipment resulting from growth in the region. There is insufficient space resulting in congested traffic flows leading to safety risks and logistical inefficiencies with materials being moved between sites on a daily basis.
- we will upgrade and expand our depot in Bendigo. Works are required to accommodate employee growth and consolidation of our contact centre into a single location. We will also update the facilities that have not been upgraded in 15 years. We will improve the current site layout to rectify poorly configured and inefficient material storage areas.
- we will develop a depot at a site in Brooklyn and reallocate some resources from our Ardeer depot. The Ardeer depot was initially established as a gas and fuel site and was not constructed to service an electricity distribution business. As a result it suffers from poor layout, including an oversupply of office space but insufficient space for material and fleet storage. Building a depot at Brooklyn provides an efficient way of meeting capacity requirements for the rapid network growth in the western region.
- we will redevelop and optimise our depot in Ballarat. The Ballarat depot has severely aged office facilities, which limits the number of resources it can house. There are poorly laid out material storage areas, limiting the type and volume of materials that can be stored on site and leads to poor traffic flow, necessitating the leasing of further storage space.

Additionally, we will increase the security of our critical assets including zone substations, distribution assets and depots in response to increasing concerns of theft and other unauthorised access. Following a review conducted by Bellrock Group using a risk-based approach, we will install new fencing, enhance monitoring measures such as anti-theft alarms and lighting, and establish a security control room to proactively manage security alerts. These measures will help ensure the safety of our people, the community and our assets. More information is available in our facilities security business case.[113]

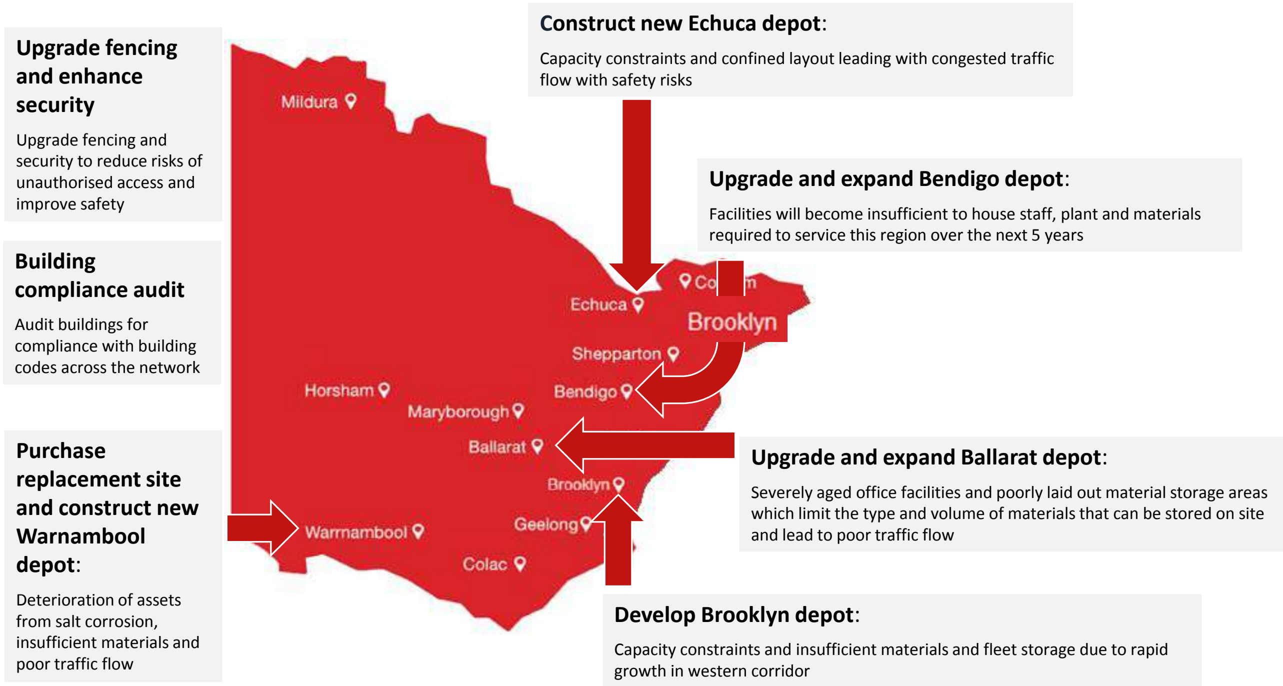
We will also conduct an audit of our sites and undertake resulting rectification works to ensure our buildings are complaint with safety, health, amenity and sustainability obligations given that many of our sites were constructed many years ago by the State Electricity Commission of Victoria or councils. The cost of these works is based on work conducted by a third party building surveyor, Visionstream Australia, to rectify two sites (with more information available in our property business case).[114]

A summary of these works is provided in figure 8.2.

[113] PAL BUS 8.07: Powercor, *Facilities security*, January 2020.

[114] PAL BUS 8.01: Powercor, *Building compliance,* January 2020.

Figure 8.2 Proposed property investment



Source: Powercor

8.1.2 We will maintain our fleet and general equipment capability

Fleet comprises of light or passenger fleet (such as cars and utility vehicles), as well as heavy or commercial fleet (such as cranes, elevated working platforms, trailers, crane borers and fork lifts). Our fleet is essential to carrying out our work efficiently and reliably.

Our forecast fleet expenditure for the 2021–2026 regulatory period reflects our average level of expenditure over 2015/16 to 2018/19. Our fleet expenditure is driven by:

- replacing existing motor vehicles in line with industry standards—we purchase, rather than lease, motor vehicles as this to be the most efficient method of sourcing vehicles
- technological developments of in-vehicle monitoring systems, which allows us to track vehicles and improve driver safety
- employee growth or network-related work programs
- compliance with legislation and standards as they apply to varying categories of fleet.

8.2 Our forecasting approach

As discussed below, we apply separate forecast approaches for our property and fleet work programs.

8.2.1 We have undertaken a bottom-up build of our property forecasts

We have undertaken a bottom-up approach to forecast our property requirements in the 2021–2026 regulatory period. We take a prudent approach that ensures we invest efficiently and that planned activities are justified from a risk perspective.

Works to our depots

We start by assessing whether the number, location and condition of our depots will remain effective to support network operations and deliver reliable services for our customers over the forecast period. This includes considering current and forecast asset condition and maintenance costs; reliability performance and customer growth; planned network projects; and employee, materials storage and fleet requirements.

We next consider a range of options to determine the efficient solution to meet our operational requirements and support our customers. We consider options including upgrades to the existing site, rebuilding depots and relocating depots. We determine the most efficient option by comparing the relative costs and benefits over the long term.

To estimate our efficient forecast expenditure, we use the following approach:

- materials and construction costs are forecast based on prior depot builds of a similar size and scale. Our depot works are undertaken by external service providers which are selected through a transparent market testing process
- land purchase costs are forecast by reviewing recent land sales in the local area to determine an average per square meter rate and applying that to the land size required for the depot
- lease costs for any temporary facilities are forecast based on reviewing the average rate for suitable properties currently available for lease in the area.

Finally, we assess the reasonableness of our portfolio from a deliverability perspective. During the current regulatory period we undertook works for five depots, including building two new depots and upgrading three additional depots. We are therefore confident in our ability to efficiently deliver property works for the five depots in the 2021–2026 regulatory period.

Physical security of facilities

We assessed the current security risks to sites across our network using the framework provided by Bellrock Group. Upon determining the total security works that needed to be conducted, we scheduled high priority works according to available resources for each year of the 2021–2026 regulatory period. We have already commenced works in the current period and have used these as the basis for forecast costs.

Building compliance uplift

In April 2019 we engaged a third-party building surveyor, Visionstream Australia, to conduct an audit of building compliance on a small sample of sites. This audit identified a number of items requiring rectification to bring the buildings into line with the Building Code of Australia and the National Construction Code. Many of the items identified are common issues that are likely to be prevalent across a wide range of our network sites—for example, relating to the height of balustrades and guard rails. There are also less common but high priority issues, such as those relating to fire safety requirements. We extrapolated from these audit findings to determine the costs of a full audit of network buildings and resulting rectification works.

8.2.2 Our fleet and general equipment forecasts are aligned with historical investment

We have used the average investment from 2015/16–2018/19 to forecast our requirements for fleet in the 2021–2026 regulatory period. Basing our forecasts off average historical fleet investment is appropriate because our investment drivers (noted previously) are expected to remain unchanged.

Our forecast investment for other general tools and equipment is also based on our average historical investment over 2015/16–2018/19. This approach ensures our forecasts are efficient, as we expect the purchase and replacement of general tools and equipment to remain relatively constant.

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9 Operating expenditure

Summary

Our operating expenditure forecast for the 2021–2026 regulatory period is an efficient, prudent and realistic forecast that allows us to achieve the operating expenditure objectives of the Rules.

We are an efficiency frontier network—we benchmark as the most efficient distributor according to the AER's 2019 benchmarking results—and have the third lowest operating expenditure per customer. In the current regulatory period, we delivered $132 million in savings from our efficient operations.

We are facing new challenges and opportunities

As an efficiency frontier network, the ongoing transformation of the energy sector (e.g. the rapid uptake of renewables, and a growing focus on data access and security) is placing upward pressure on our historical operating investment. Our operations are also increasingly being challenged by climate change, through extreme weather, bushfire risk and faster deterioration of assets. To successfully transition and manage these challenges proactively and efficiently, our forecasts include incremental investments for targeted step changes, including:

- the ongoing operation of new bushfire prevention technology—rapid earth fault current limiters (**REFCL**)—mandated by the Victorian Government
- new obligations under the *Environment Protection Amendment Act 2018* and draft regulations
- strengthened security requirements for the protection of data under the *Security of Critical Infrastructure Act*
- reclassification of the 'food belt' to high bushfire risk area (**HBRA**), requiring increased vegetation and maintenance activities
- increasing bushfire insurance premiums driven by unprecedented tightening of global insurance markets.

There are also opportunities for us to deliver customer benefits and cost savings during the 2021–2026 regulatory period, including:

- enabling more solar to be connected to the network, delivering economic benefits for all customers and responding to our changing customer needs
- delivering cost savings for customers by migrating on-premise IT infrastructure to cloud hosting
- reducing bushfire risk through implementation of new HV fuse technology.

Our forecasts reflect our efficient operations

We use the AER's base–step–trend approach to forecast our required operating expenditure. We have selected 2019 as the efficient base year, and have engaged independent consultants to forecast trends in economic factors to be applied to this base.

While we have applied the AER's pre-emptive productivity adjustment to our efficient base operating expenditure, we must be provided funding for implementing new innovative initiatives and productivity-enhancing projects necessary to achieve these productivity improvements. As we have already achieved considerable productivity improvements through investment in new technologies and management practices, we have limited capacity to achieve additional productivity gains through business-as-usual initiatives in 2021–2026.

Our operating expenditure allows us to fund our everyday operations, to meet and manage our compliance obligations and ensure our services meet relevant quality, reliability, safety and security of supply standards. Operating expenditure covers:

- IT maintenance and leasing
- customer and corporate services
- asset inspections, maintenance and repair
- vegetation pruning around our assets
- emergency response
- various other ongoing expenses.

Figure 9.1 shows the largest categories of our operating expenditure in 2019, how we have achieved savings over time and how this meets our customers' priorities.

Figure 9.1 Operating expenditure categories in 2019

30% IT, customer and corporate services	24% Asset inspection, maintenance and repair	17% Vegetation management	14% Emergency response	15% All other operating expenditure
• We have a corporate team that delivers customer service and ensure our business runs efficiently • Customer information and data will soon be handled locally • We've undertaken a 'World Class' savings program to ensure we only employ the staff we need and who are best suited for the job	• As part of our comprehensive asset management strategy, we inspect our assets periodically and maintain or repair assets based on their inspected condition • We prefer to maintain and repair assets where they can still be operational and safe, rather than replace them before their time • We are modernising inspections with lasers, drones and through smart meter data, which will lead to more efficient and accurate results in the future	• We prune trees and other vegetation around power lines periodically to a distance determined by Electricity Safety (Electric Line Clearance) Regulations 2015 • Our pruning cycle is three years, which controls pruning costs while ensuring visual amenity for our customers • In 2015 we renegotiated our external contract for vegetation management, resulting in on-going savings to customers	• We have a highly trained crew who are available 24/7 for emergency response • Our crew are distributed across the network to minimise travel time in the case of emergency and when conducting other works • We seek to recover the cost of emergency works from third parties as much as possible to minimise the impact on our customers	• Other operating expenditure includes our licence fee, equipment leasing and other smaller on-going expenses • We ensure efficiency in all other operating expenditure by market-testing leasing services and continually reviewing contracts
Data security is very important to our customers	Our customers want us to be more innovative in our operations	Most of our customers are satisfied with our pruning cycles	Our customers rightly expect world-class safety outcomes	Our customers don't want us to spend $1 more than necessary

Source: Powercor

A summary of the components of our operating expenditure forecast for the 2021–2026 regulatory period is shown in table 9.1.

Table 9.1 Operating expenditure forecasting approach 2021–2026 ($ million, 2021)

Operating expenditure	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Base	243.6	243.6	243.6	243.6	243.6	1,218.2
Base adjustments	10.5	10.5	10.5	10.5	10.5	52.3
Re-classifications	6.7	6.7	6.7	6.7	6.7	33.5
Output growth	5.7	10.7	15.7	20.7	25.9	78.6
Labour escalation	4.1	8.7	13.3	17.6	21.5	65.1
Productivity	-1.4	-2.7	-4.2	-5.7	-7.2	-21.1
Step changes	35.9	16.3	16.8	14.2	14.8	98.0
Debt raising costs	2.2	2.4	2.5	2.6	2.6	12.2
Total	**307.4**	**296.0**	**304.9**	**310.1**	**318.4**	**1,536.9**

Source: Powercor

9.1 What we plan to deliver

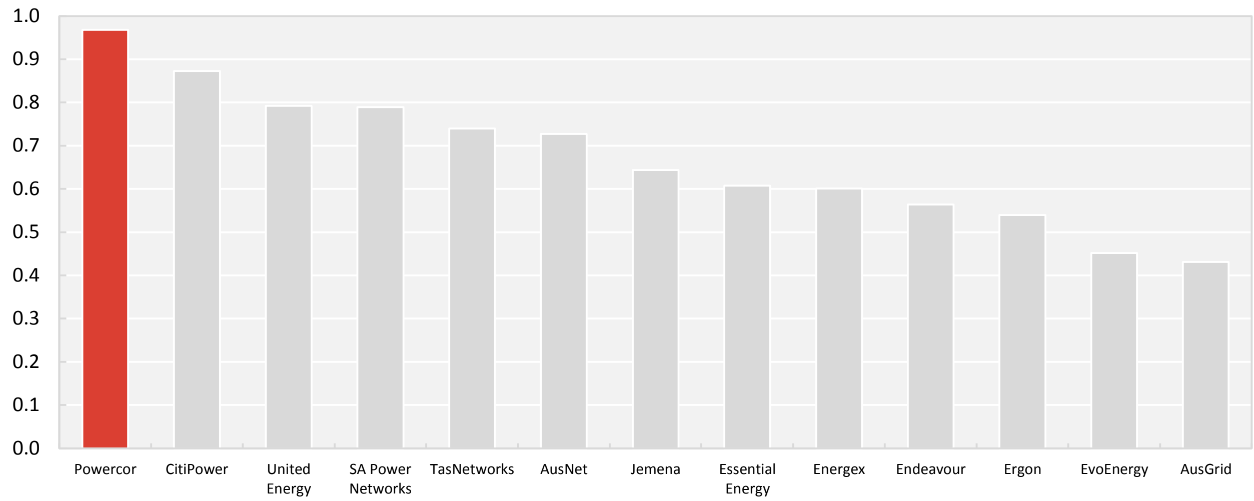
Our operating expenditure is among the lowest in the country. Our customers get value for money as we deliver a safe, reliable and dependable network that meets our customers' needs at the most efficient cost.

Our stakeholders and customers have been clear that they expect to not pay a dollar more, nor pay a day earlier than necessary for investments required to maintain our network. We support this view and are striving to do more for less.

As the efficiency frontier distributor in Australia—along with CitiPower and United Energy (distributors we also own and operate)—we set the benchmark for the entire industry on the least-cost way to operate the network. We are proud of this leadership position, and will continue to invest only where prudent and efficient so that we remain at the frontier.

According to AER operating expenditure benchmarking, our operating expenditure is the most efficient in the NEM. Figure 9.2 summarises the results of the most recent AER benchmarking study.

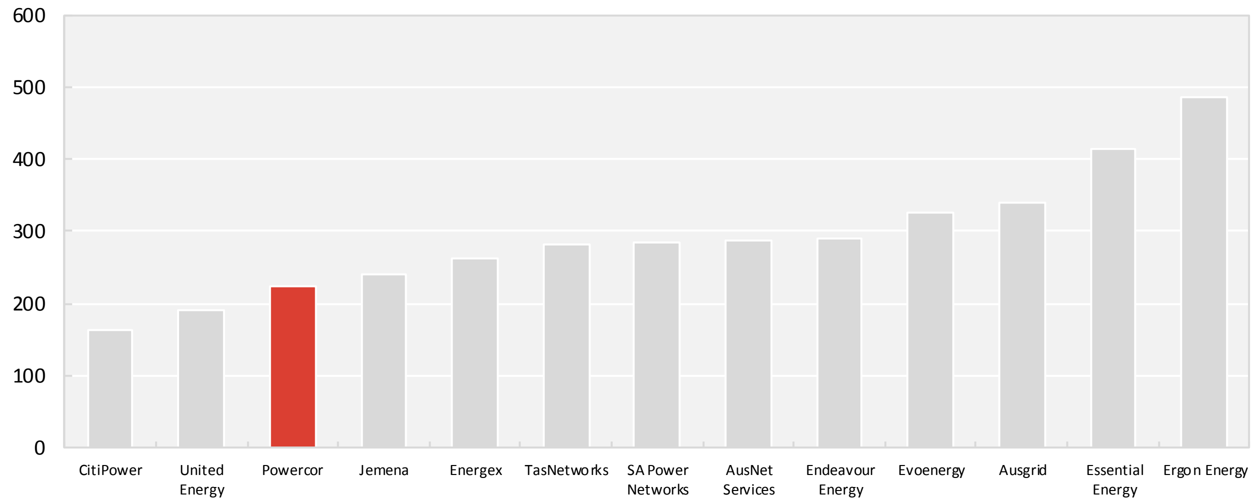
Figure 9.2 Operating expenditure efficiency scores from Cobb-Douglas stochastic frontier analysis (2006–2018)



Source: PAL ATT045: Australian Energy Regulator, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2019

Similarly, our operating expenditure per customer is third lowest across the NEM, higher only than our shared networks, CitiPower and United Energy. In 2018, we ran our operations and serviced our customers with almost 40% lower operating expenditure per customer than the average distributor in New South Wales and Queensland. Figure 9.3 summarises the operating expenditure per customer across the NEM.

Figure 9.3 Operating expenditure per customer across the NEM, 2018 ($2018)



Source: PAL ATT045: Australian Energy Regulator, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2019

9.1.1 We are investing to ensure we meet new or changed regulatory obligations

Our operating expenditure in our 2019 'base' year reflects the efficient costs a prudent operator in our circumstances would require to achieve the operating expenditure objectives.[115]

Our base operating expenditure reflects our current operating environment, having regard to our current service targets, regulatory obligations and other prevailing environmental circumstances. As an efficiency frontier network, we have no contingency in our operations to absorb increasing costs from growing regulatory and service obligations, or material increases in the cost of complying with existing obligations and delivering services due to changes outside our control.

To achieve the operating expenditure objectives, therefore, we consider it prudent to account for increasing cost pressures from circumstances outside of our control through operating expenditure step changes. Table 9.2 summarises these step changes resulting from new regulatory obligations, and we expand on these below. Section 9.1.2 outlines additional step changes for new services that will allow us to deliver more customer benefits. Our assessment included identifying negative step changes over the 2021–2026 regulatory period, of which no material items were identified.

Table 9.2 Step changes resulting from new regulatory obligations or increasing costs of existing obligations ($ million, 2021)

Step change	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Five-minute market settlement	0.6	0.8	1.0	1.2	1.5	4.9
Security of critical infrastructure	3.1	2.8	2.8	2.9	2.9	14.5
Increasing insurance premiums	1.0	1.0	1.0	1.0	1.0	5.0
EP Amendment Act 2018 and draft regulations	3.2	3.3	3.1	0.0	0.1	9.6
REFCL on-going costs	1.8	2.2	2.8	3.2	3.3	13.3
Reclassification of food belt to HBRA	20.8	0.7	-	-	-	21.5
Increase in ESV levy	0.7	0.8	0.8	0.8	0.9	4.0
Financial year RIN	0.4	0.4	0.4	0.4	0.4	1.8
Total	**31.5**	**11.9**	**11.8**	**9.5**	**10.0**	**74.7**

Source: Powercor
Notes: Forecast shown includes labour escalation (not applied to increasing insurance premiums or increase in ESV levy step changes).

We have also identified two additional regulatory obligations that are likely to result in a step change in costs during 2021–2026:

- electrical line-worker licensing—the Victorian Government at the 2018 Victorian election committed to a licensing scheme for electrical line-workers, expected to commence on 1 January 2021

[115] The operating expenditure objectives of the Rules for standard control services require us to meet or manage the expected demand, comply with all applicable regulatory obligations or requirements, maintain the quality, reliability and security of supply, and maintain the safety of the distribution system.

- Electricity Distribution Code review—the Essential Services Commission of Victoria (**ESCV**) is currently reviewing the Electricity Distribution Code, results of which are expected to be finalised in 2020.

As these changes are still under consideration, we do not have sufficient information to quantify the impact on our operating expenditure. We may propose step changes for these changes in our revised regulatory proposal.

Five-minute settlement

On 28 November 2017, the Australian Energy Market Commission (**AEMC**) amended the Rules to change the financial settlement period for the electricity wholesale market from 30 minutes to five minutes, to align with the operational dispatch of electricity. This is known as the five-minute settlement rule change.[116] As a result of the rule change we are required to capture, store, process and share meter data in five minute intervals for meters installed from 1 December 2018, rather than the current 30 minute intervals.

By December 2022, we must provide five-minute data to market for meters installed from December 2018.[117]

To ensure we comply with the rule change, we will incur incremental operating expenditure during the 2021–2026 regulatory period which is not accounted for in our 2019 base, including:

- additional operating expenditure for increased wide area network capacity to transport increased volume of meter data between IT systems
- additional operating expenditure to manage the increase in manual validations of meter data exceptions.

Our forecasting approach for these incremental costs, including our options analysis, is set out in our attached step change model and five-minute settlement business case.[118]

Strengthening the security of critical infrastructure

In 2017, the Australian Government introduced a series of requirements to address the national security risks of espionage, sabotage and coercion associated with foreign involvement, through ownership, offshoring, outsourcing and supply chain arrangements, in critical infrastructure. These requirements include our electricity distribution systems.

More specifically, the critical infrastructure requirements include a subset of new requirements concerning system and data controls. To meet these requirements, we must transition to full compliance in accordance with the work plan approved by the Australian Government. The majority of our customers also see data security as vital in an increasingly technology-driven world.

These critical infrastructure system and data control requirements are new 'regulatory obligations or requirements' (within the meaning given to that term by the NEL) associated with the provision of standard control services.[119] In its draft decision for SA Power Networks in October 2019, the AER also deemed these

116 PAL ATT220: Australian Energy Market Commission, *Rule determination, National Electricity Amendment (Five Minute Settlement) Rule*, November 2017.

117 PAL ATT220: Australian Energy Market Commission, *Rule determination, National Electricity Amendment (Five Minute Settlement) Rule*, November 2017, p. 121.

118 PAL BUS 7.09: Powercor, *Five minute settlement*, January 2020; PAL MOD 7.14 - 5 minute settlement - Jan2020 – Public.

119 Compliance with those requirements is required in order to achieve the operating expenditure objective set out in clause 6.5.6(a)(2) of the Rules or, in the alternative, clause 6.5.6(a)(1), (a)(3) and/or (a)(4) of the Rules.

critical infrastructure system obligations are 'new regulatory obligations or requirements as defined in the [NEL]'.[120]

As a result, we will incur material ongoing operating expenditure in the next regulatory period that is additional to the expenditure reflected in our 2019 base operating expenditure. Further details are provided in our attached step change model and critical infrastructure business case.[121]

Increasing insurance premiums

We insure for general liability through insurers that operate on a global scale. Over the past 12–18 months, the global market for insurers has experienced significant disruption driven by increasing natural catastrophe events. Specific to insurance for bushfire risk, recent major events with significant consequences include:[122]

- 2018 wildfires in Camp and Woolsey, California, with $24 billion damage
- 2017 wildfires in Tubbs, Atlas, and Thomas, California, with $17 billion damage
- 2016 wildfires in Fort McMurray, Canada, with $4 billion damage.

The rising number of bushfire events in a short time period has resulted in significant insurer losses and insurer exits from the market. According to insurance specialists Marsh, in 2019 the global insurance market experienced sizeable capacity withdrawal due to a combination of insurer consolidation, appetite changes and (re)insurers' hardening criteria for deploying capacity.[123]

Market exits, reductions in offered capacity and hardening of insurance criteria have resulted in a material increase in bushfire insurance premiums, increasing our overall insurance costs. Our insurance premiums for the year ending 30 September 2020 (2019/20) are 31% higher compared to 2018/19 for the same level of cover.[124] This is a second consecutive year of premium increases of 30–35% in magnitude.

These premium rises are significantly higher than those expected from normal market conditions and present material cost increases outside our control. As such, we are proposing a step change to allow us to continue to meet the National Electricity Objective while addressing challenges outside of our control.

Marsh predicts global markets for specialist insurers will continue to experience capacity disruptions over the short-to-medium term.[125] This is expected to lead to further premium increases during the 2021–2026 regulatory period. While we expect costs will continue to grow, we are only proposing a step change that is equivalent to the difference in our actual premiums in 2019/20 and the 2019 base year.

Our forecasting approach for these incremental costs is set out in our attached step change model.[126]

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120 PAL ATT215: Australian Energy Regulator, *Draft Decision SA Power Networks, Distribution Determination 2020 to 2025, Attachment 6, Operating expenditure*, January 2019, p.42.

121 PAL BUS 9.01: Powercor, *Security of critical infrastructure*, January 2020; PAL MOD 9.01 - Step changes - Jan2020 – Public.

122 PAL ATT096: Marsh, *Liability Market and Claims Overview*, October 2019.

123 PAL ATT096: Marsh, *Liability Market and Claims Overview*, October 2019.

124 PAL ATT051: JLT, *Invoice for insurance*, January 2020.

125 PAL ATT096: Marsh, *Liability Market and Claims Overview*, October 2019.

126 PAL MOD 9.01 - Step changes - Jan2020 – Public.

New Environment Protection Amendment Act 2018 and draft regulations

We operate a health, safety and environment (**HSE**) management system that sets out a program of works and practices to comply with all HSE legislation and regulatory obligations, including environmental obligations. Further, 89% of our customers support us managing the network in an environmentally sustainable way.

The current legislation and regulations relevant to our environmental obligations (specific to this business case) are:

- the *Environment Protection Act 1970* (**EP Act 1970**)
- state environment protection policies and waste management policies.

These are administered and managed by the Environment Protection Authority Victoria (**EPAV**).

The *Environment Protection Amendment Act 2018* will repeal the EP Act 1970 from 1 July 2020 to establish a proactive regulatory approach to preventing waste and pollution impacts, rather than managing the impacts after they occur. In August 2019, the Victorian Government published the draft Environment Protection Regulations (**draft regulations**), along with the regulatory impact statement (**RIS**). Final regulations are expected in March 2020.

To comply with the new proactive obligations, we will incur material operating expenditure during 2021–2026 regulatory period that is incremental to our 2019 base year. These costs relate to identifying, assessing and testing potential environmental risks of our operations, as well as remediation works for contaminated sites. For remediation of oil contamination on land, which is the largest cost item, we have developed a desktop risk assessment and have ranked the contaminated sites according to level or risk of harm. For our cost estimate, we have included the remediation of the highest risk sites only in the 2021–2026 regulatory period.

Further detail on this change, including information on the highest risk sites and the corresponding options analysis, are detailed in attached step change model and environmental business case.[127]

Given the estimated costs are based on the preferred option of the draft regulations in the RIS, our forecasts are subject to change when the final regulations are published. We expect to review the implications of the final regulations on our operations, and update the options and the costings with a more detailed assessment for our revised regulatory proposal.

REFCL incremental ongoing operating costs

We are required to progressively install rapid earth fault current limiters (**REFCLs**) at 22 zone substations to comply with the *Electricity Safety (Bushfire Mitigation) Amendment Regulations 2016* (**Amended Bushfire Mitigation Regulations**) which were implemented in Victoria on 1 May 2016. A REFCL is a network protection device, normally installed in a zone substation, which can reduce the risk of a fallen powerline causing a fire-start.

Once an installed REFCL is commissioned and becomes operational, we must demonstrate compliance against the performance criteria to ESV annually. To ensure we meet the performance criteria, we must undertake compliance testing, re-balancing works and technical and engineering support.

For REFCLs that become operational in 2019 onwards, this will result in material incremental annual operating expenditure that is not reflected in our 2019 base operating expenditure. We propose a step change, therefore, for undertaking annual compliance testing, annual re-balancing works and ongoing technical and engineering

[127] PAL BUS 4.01: Powercor, *EP Amendment Act 2018*, January 2020; PAL MOD 4.08: Powercor, *Environmental risk*, January 2020.

support for REFCLs that become operational after 2019. This ensures we meet the requirements of the Amended Bushfire Mitigation Regulations and our bushfire mitigation plan (**BMP**).

Our forecasting approach for ongoing REFCL-related operating costs is set out in our attached step change model and business case.[128]

Reclassification of the 'food belt' to high bushfire rated area

The Country Fire Authority (**CFA**) is currently reviewing the hazard ratings it has assigned to land associated with Victorian distribution network service providers, namely low bushfire risk areas (**LBRA**) and high bushfire risk areas (**HBRA**). Through our preliminary discussions, the CFA and ESV have indicated that a large portion of land located north of Shepparton and north-west through to Mildura (**food belt**) is likely to be reclassified from LBRA to HBRA. We expect the new reclassification will be effective on 1 November 2021, for the 2021/2022 summer.

In accordance with the Electric Line Clearance Regulations and our BMP (which has been accepted by ESV), in HBRA we must:

- increase vegetation clearance levels
- undertake more frequent pole inspections from 5 years to 2.5 years
- replace surge arrestors and fit span with spreaders.

To ensure we comply with the obligations applying to HBRA in the food belt area, we will incur material incremental operating expenditure during 2021–2026 which is not reflected in our 2019 base year. Our forecasting approach for these incremental costs is set out in attached step change model, and further justification is set out in our food belt business case.[129]

Increase in ESV levy

We are required to make levy payments to ESV. The levy payment schedule is set by ESV on an annual basis. On 30 April 2019, ESV communicated a material increase in its levy, including a 22% increase from 2018/19 to 2021/22 and annual 3% ongoing year-on-year increases, as shown in ESV's attached fee levy schedule.[130] These material increases in the levy are beyond our control and are not captured in our 2019 base operating expenditure. Further detail on this is detailed in attached step change model.[131]

Financial year RIN

The Victorian Government has changed the next Victorian distributors' regulatory period from calendar years to financial years. We currently prepare financial statements on calendar year basis which is aligned with RIN reporting on a calendar year basis. This means we only incur labour and audit costs for one set of financial accounts.

From 2021/22, we will be required to prepare and get audited a second set of financial accounts each year to enable population of the RINs on a financial year basis. The cost of preparing and auditing a second set of financial accounts is not reflected in our 2019 base operating expenditure.

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128 PAL BUS 9.02: Powercor, *REFCL annual operating costs,* January 2020; PAL MOD 9.01 - Step changes - Jan2020 – Public.

129 PAL BUS 9.03: Powercor, *Food Belt HBRA*, January 2020; PAL MOD 9.01 - Step changes - Jan2020 - Public.

130 PAL ATT041: Energy Safe Victoria, *Forum minutes and levy*, February 2019.

131 PAL BUS 4.01: Powercor, *Environmental Protection Amendment Act 2018*, January 2020; PAL MOD 9.01 – Step changes – Jan2020 – Public.

We have forecast the annual cost for preparing and auditing a second set of financial accounts based on our 2018 actual costs. These costs are included in our attached step change model.[132]

9.1.2 We are investing to deliver additional customer benefits

In addition to our compliance-driven step changes, we are investing to deliver new customer benefits. This requires operating expenditure that is not reflected in our 2019 base year, based on the following criteria:

- the benefits to customers exceed the incremental operating expenditure
- the costs cannot be met from existing regulatory allowances or from other elements of the expenditure forecasts
- reflects an efficient trade-off of operating expenditure and capital expenditure
- reflects only the incremental costs above our 2019 base year and the costs are material
- is not productivity enhancing.

Table 9.3 summarises our step changes that deliver new customer benefits.

Table 9.3 Step changes that deliver new customer benefits ($ million, 2021)

Step change	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Solar enablement	1.3	1.3	1.5	1.0	1.0	6.2
IT cloud migration	0.9	0.9	1.2	1.5	1.5	5.9
EDO fuse replacement	2.2	2.2	2.2	2.3	2.3	11.2
Total	**4.4**	**4.4**	**5.0**	**4.7**	**4.8**	**23.3**

Source: Powercor
Notes: Forecast shown includes labour escalation.

Solar enablement

As outlined in section 6.1.1 of our augmentation chapter, our customers are seeking to export excess solar back into the network. Where this is efficient (i.e. the benefits exceed the costs) we will enable this.

The net benefit to our customers of this program is over $76 million. The benefits we have calculated are the reduction in wholesale generation fuel costs and carbon reduction benefits from solar; benefits that all our customers (even those without solar) receive.

Delivering these benefits requires a mix of capital, and incremental operating expenditure to remove voltage constraints and enable more exports. Incremental operating expenditure, specifically, is needed to:

- 'tap down' distribution transformer voltages where possible as a less expensive option to, and reduce the need, for capital investment
- compliance and monitoring of customers' inverter settings (e.g. if installers fail to apply the required new inverter settings that reduce the voltage rise from exporting solar, voltage rises will be significantly higher

132 PAL MOD 9.01 - Step changes - Jan2020 – Public.

than forecast—as a result, the full value of the net benefits will not be realised and there will be inequitable outcomes whereby customers without the inverter settings applied will be able to export more, at the expense of others.

This operating expenditure is incremental to our base year expenditure as our current policy limits solar exports (hence, the need to remove constraints), and reflects the step up in solar installations resulting from the Victorian Government's Solar Homes subsidy program. More information, including our considerations of the incremental nature of these costs, is available in the solar enablement business case.[133]

ICT cloud migration

As discussed in section 7.1.2, we own and maintain the majority of our ICT infrastructure on-premise and we incur capital expenditure to grow and refresh our on-premise infrastructure capabilities. With the maturing market for cloud-based services, there is an opportunity for us to migrate some of our existing ICT infrastructure to cloud-hosting. Under cloud-hosting, ICT infrastructure is owned and managed by third party vendors and typically paid for on a subscription basis.

Our proposal represents an efficient trade-off between operating investment and capital investment. The proposed migration to cloud-hosting delivers savings to customers through a reduction in ICT capital expenditure which exceeds the increase in operating expenditure for cloud subscriptions. Our proposed cloud migration also provides longer term benefits of cloud-hosting, such as easy scalability and adaptability of our ICT environment to changing requirements, meaning customers will only pay for the capacity and services we need.

To deliver customer savings through efficiently migrating ICT infrastructure to cloud-hosting, we will incur material incremental operating expenditure which is not reflected in our 2019 base operating expenditure. Further details on these costs are set out in our attached in the ICT cloud migration business case and model.[134]

EDO fuse replacement

Across our high voltage (**HV**) network we have expulsion dropout (**EDO**) fuses that can, in some cases, start a fire. We can reduce bushfire risk as far as practicable by replacing a large number of EDO fuses with fault tamers in highest consequence bushfire areas. Fault tamers are alternative fuses that have a lower risk of starting a fire, and our customers strongly support safety initiatives that use modern technology to reduce bushfire safety risk.

We considered three options to reduce bushfire risk, using risk monetisation modelling. The preferred option is the proactive replacement of all EDO fuses with fault tamers in high-consequence electrical line construction areas (**ELCA**), and replacement of EDO fuses with fault tamers in high bushfire risk areas (**HBRA**). This option delivers the highest net benefit to our customers and will result in the largest reduction in bushfire risk across our network, consistent with our obligations under the *Electricity Safety Act 1998*.

Fuse replacements are part of our maintenance and repair operating expenditure. Our proposed replacement program would result in a material increase in our operating expenditure not captured in our 2019 base year. Our latest BMP, accepted by ESV, establishes the use of fault tamers in-lieu of EDO fuses.

The full details of the risk monetisation and options analysis is set out in attached business case and models.[135]

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133 PAL BUS 6.02: Powercor, *Solar enablement*, January 2020.

134 PAL BUS 7.10: Powercor, *Cloud infrastructure*, January 2020, PAL MOD 7.15 - Cloud infrastructure cost - Jan2020 - Public; PAL MOD 7.16 - Cloud infrastructure risk - Jan2020 - Public.

135 PAL BUS 9.04: Powercor, *EDO replacement*, January 2020; PAL MOD 9.05 - EDO ELCAs risk - Jan2020 - Public; PAL MOD 9.06 - EDO HBRA risk - Jan2020 - Public

9.2 Our forecasting approach

We have used the AER's 'base–step–trend' approach to develop our proposed operating expenditure for the 2021–2026 regulatory period. This is consistent with the AER's preferred model, as set out in its expenditure forecast assessment guideline.

Our approach is as follows:

- nominate 2019 as the efficient revealed base year
- adjust our base year expenditure to include an efficient forecast for activities which are not fully reflected in the base year expenditure, including:
  - review of non-recurrent costs
  - adjustment for services reclassified as standard control
  - adjustment for costs reclassified as operating expenditure
  - adjustment for forecast Guaranteed Service Level (**GSL**) payments rather than actuals in 2019
- add to the base year the efficient level of operating expenditure determined by applying a rate of change, comprising real price escalation, output growth and productivity
- add the efficient level of forecast step changes for the 2021–2026 regulatory control period
- add the efficient forecast of debt raising costs.

We explain the components of our forecasting approach in more detail in the following sections.

9.2.1 Our base year operating expenditure is efficient

We nominate 2019, the fourth year of the 2016–2020 regulatory period, as the efficient base year for our operating expenditure forecast for the 2021–2026 regulatory period. We consider our base year expenditure is efficient for the following reasons:

- the AER has consistently classed us as one of the efficiency frontier networks in the NEM, based on its operating expenditure benchmarking analysis[136]
- we are subject to an incentive framework to which we have responded and continue to respond
- our private ownership structure promotes efficient expenditure, evident in savings generated over the past five years
- we have among the lowest operating expenditure per customer, while continuing to provide a safe and dependable network that is available 99.97% of the time
- a large proportion of our operating expenditure is outsourced to external contractors who benefit from economies of scale
- we ensure efficiency of our operations by market-testing and engaging competitive contracts where possible (e.g. in 2015, we renegotiated our vegetation management contract which resulted in an ongoing saving to customers)

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136 PAL ATT045: Australian Energy Regulator, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2019, p. iv.

- our labour costs are efficient and competitively priced, and our corporate and field staff are strategically located across the network to minimise travel times and response times in emergency situations.

While we consider every year during the 2016–2020 regulatory period is efficient, we have used 2019 as the base year as it represents the most recent actual audited reported performance that will be available before the AER is required to make its draft decision.[137] The currency of this data (relative to earlier years) ensures our forecasts are based on up-to-date data. That the data is audited ensures the starting point for our forecasts is robust.

9.2.2 We have adjusted our base year to better reflect future ongoing operating expenditure

We have reviewed our base year operating expenditure for any non-recurrent expenditure and future ongoing expenditure that may not be reflected in the base. While no non-recurrent operating expenditure was discovered, we identified several activities for which the 2019 base year does not reflect the expenditure for these activities going forward. A summary of these activities, and the net annual adjustments to our 2019 base year operating expenditure, are set out in table 9.4.

Table 9.4 Annual base adjustments ($ million, 2021)

Base adjustments	Total (per annum)
GSL adjustment	0.3
Reclassification of emergency recoverable works as standard control service	0.3
Reclassification of operating expenditure related to the smart meter communications network	1.5
Reclassification of 'wasted truck visits' for faults on the customer side of the connection point	1.2
Reclassification of minor repairs as operating expenditure	3.8
Rate of change: 2020 and half-year 2021	10.1
Total	**17.2**

Source: Powercor

Adjustment for forecast GSL payments rather than actuals in 2019

We are required to make GSL payments to customers who experience reliability that is worse than specified performance thresholds in the Electricity Distribution Code. These payments may exhibit significant volatility across years based on a range of exogenous factors. Given this variability, we have removed actual GSL payments for 2019 from our base year expenditure, and replaced it with a forecast reflecting the average of GSL payments over the period 2014–2019. This approach is consistent with that adopted by the AER in previous regulatory decisions.

137 For this Regulatory Proposal our 2019 operating expenditure is an estimate. Our revised proposal will be updated for our actual audited 2019 operating expenditure.

Reclassification of emergency recoverable works as standard control

In its 2021–2026 framework and approach paper, the AER reclassified emergency recoverable works as standard control (from an unclassified service). Emergency recoverable works are carried out for emergencies that are the fault of third parties.[138]

The Rules require us to seek funding from third parties to recover the cost of the service. However, we cannot recover costs from all third parties due to circumstances outside of our control, including third party insolvencies.

While we will continue to seek funding from third parties to recover the cost of emergency recoverable works, our best forecast for the base adjustment reflects the average net cost from emergency recoverable works over the 2014–2018 period. This approach is consistent with that adopted by the AER in Ausgrid's final determination in April 2019.[139]

We are only proposing to adjust base operating expenditure for the amount we are historically unable to recover from third parties. That way our customers only pay a small portion for the residual cost of emergency recoverable works.

Reclassification of cost of 'wasted truck visits' for faults on the customer side of the connection point

The AER's 2021–2026 framework and approach paper also reclassified 'wasted truck visits' (from an alternative control service in the 2016–2020 regulatory period).[140] Wasted truck visits are where a distributor sends a truck to a customer's premises after receiving a complaint about a power outage or power quality issue, only to find on arrival that the issue is on the customer side of the connection point.

Our forecast base adjustment for these wasted truck visits is estimated using our 2014–2018 actual expenditure.

Reclassification of operating expenditure related to the smart meter communications network

Our use of data analytics with smart meter data has now become part of our business-as-usual network optimisation. Our customers have told us they want us to keep finding more innovative ways for managing the network, and they will continue to benefit through lower costs from managing our network in this manner.

For the 2021–2026 regulatory period, we have allocated 88% of the operating expenditure for maintaining our communications network from metering to standard control services. This amount represents the percentage of data transmitted through the smart meter communications network for network management purposes, the benefits of which are shared by all our customers.

This approach is a fairer outcome for all customers. For more information refer to our metering chapter.

Adjustment for reclassification of minor repairs as operating expenditure

We are proposing to reclassify 'minor repairs' from capital expenditure to operating expenditure. Typically, minor repairs include labour-intensive work that results from asset failure or identified defects that could result in an imminent asset failure (if not repaired).

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138 PAL ATT044: Australian Energy Regulator, *Final framework and approach, AusNet Services, CitiPower, Jemena, Powercor and United Energy Regulatory control period commencing 1 January 2021*, January 2019, pp. 26–27.

139 PAL ATT241: Australian Energy Regulator, *Final Decision*, *Ausgrid Distribution Determination 2019 to 2024*, April 2019, pp.32-33.

140 PAL ATT044: Australian Energy Regulator, *Final framework and approach, AusNet Services, CitiPower, Jemena, Powercor and United Energy Regulatory control period commencing 1 January 2021*, January 2019, p.32.

Treating minor repair costs as operating expenditure better reflects the nature of the work—the costs are incurred to maintain the age of the asset and the work does not result in the creation of a new asset. We consider these costs to be more akin to maintenance and repair which is immediately expensed, rather than refurbishment or replacement of assets that are depreciated over a longer period.

We propose to adjust our base year operating expenditure for the total cost of minor repairs in 2019 and remove any forecast minor repairs from our capital replacement expenditure forecast. These changes are net present value (**NPV**) neutral, which means customers are no worse-off in the long term.

This is reflected in our updated cost allocation method, and our audited re-cast reset RIN transfers minor repairs from replacement capital expenditure to maintenance.[141]

Rate of change for 2020 and half year 2021

We have added to the base year the efficient level of operating expenditure determined by applying a rate of change, comprising real price escalation, output growth and productivity. In accordance with the AER's approach, the rate of change is used to trend forward our base year expenditure to the start of the new regulatory period.

9.2.3 We trend forward our base year for expected changes in economic and network conditions

Our actual operating expenditure in the base year reflects the economic and network conditions that prevailed during 2019. It is reasonable to expect these economic and network conditions to change over the 2021–2026 regulatory period, and therefore, our operating expenditure forecasts must change to ensure we can continue to achieve the operating expenditure objectives of the Rules.[142]

The AER's expenditure forecast assessment guideline also sets out the following reasons why efficient operating expenditure in the forecast period may differ from the base level of expenditure:[143]

- real price growth—this relates to changes in the prices we pay for labour and non-labour inputs used in our operations. Real price growth is the growth rate in prices relative to growth in the consumer price index (**CPI**). As real input prices change our efficient level of expenditure will change
- output growth—this relates to changes in the network size and demand for network services. It is reasonable that as the scale of operations increases our efficient costs will increase
- productivity growth—productivity growth reflects shifts in the production possibility frontier delivered through technology advancements or other innovations. It does not reflect reductions in operating expenditure from removing inefficiencies or business as usual IT upgrades.

We have developed forecasts of each of the above components and applied these to develop our efficient operating expenditure forecasts. Our approach is described below and in the supporting attachments as indicated in each subsection.

141 PAL RIN002 - Workbook 2 - New historical CAT - Jan2020 - Public. PAL ATT027 - Cost allocation method - Jan2020 - Public.

142 The operating expenditure objectives of the Rules for standard control services require us to meet or manage the expected demand, comply with all applicable regulatory obligations or requirements, maintain the quality, reliability and security of supply, and maintain the safety of the distribution system.

143 PAL ATT163: Australian Energy Regulator, *Expenditure forecast assessment guideline for electricity distribution*, November 2013.

9.2.4 Forecast real price growth

Over the 2021–2026 regulatory period, input prices for labour have been forecast by our independent expert, BIS Oxford Economics (**BIS Oxford**) to grow at a faster rate than CPI. Conversely, we currently have no evidence our non-labour input prices will grow at a greater rate than CPI. We have therefore only included a real price escalation for labour in our forecast.

Real labour price growth

We engaged BIS Oxford to provide independent labour price forecasts for the 2021–2026 regulatory period. BIS Oxford developed forecasts of the Australian Bureau of Statistics (**ABS**) Electricity, Gas, Water and Waste Services (**EGWWS**) Wage Price Index (**WPI**) for Victoria. This is consistent with the AER's preferred approach to forecasting labour price growth.

We engaged Frontier Economics (**Frontier**) to assess the accuracy of BIS Oxford's forecasting history for Victorian real EGWWS WPI. Frontier found that BIS Oxford have been the more accurate forecaster compared to the AER's preferred forecaster Deloitte Access Economics with regards to the real growth in the Victorian EGWWS WPI.

BIS Oxford also provided advice on the calculation of the proposed increases to the superannuation guarantee. As per the Minerals Resource Rent Tax Repeal and Other Measures Bill 2014, Schedule 6—Superannuation Guarantee Charge percentage, the superannuation guarantee is scheduled to increase progressively from 9.5% on 1 July 2020 to 12% on 1 July 2025, as shown in table 9.5.[144]

Table 9.5 Change in superannuation guarantee charge (%)

Description	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Charge percentage	9.5	10.0	10.5	11.0	11.5	12.0

Source: The Parliament of the Commonwealth of Australia

According to BIS Oxford's research, the superannuation guarantee charge is not included in the ABS's WPI or the Average Weekly Earnings measures and is treated as a labour 'on-cost'.[145] The superannuation guarantee charge, therefore, needs to be added to the forecast increases in the WPI when escalating labour prices over the forecast regulatory period.

Our labour price growth forecasts include the effect of the change in the superannuation guarantee charge, as added to the BIS Oxford independent forecasts. The forecast real labour price growth rate is shown in table 9.6.

Table 9.6 Labour price growth forecast for 2021–2026 (%)

Description	2021/22	2022/23	2023/24	2024/25	2025/26
Labour price growth forecast	2.00	2.17	2.16	1.91	1.71

Source: BIS Oxford Economics

Labour price growth over the 2021–2026 period will be buoyant as a result of strong population growth and a rebounding economy. Victoria's population, particularly in Melbourne, is expected to be stronger than the

144 PAL ATT214: The Parliament of the Commonwealth of Australia, House of Representatives, *Minerals Resource Rent Tax Repeal and Other Measures Bill 2014, as passed by both Houses*, 2013-2014.

145 PAL ATT014: BIS Oxford, *Labour escalation*, April 2019.

national average as migration from interstate increases. Victoria's economy is expected to rebound from stronger population growth, higher exports and household consumption from the weak Australian dollar, and stronger business investment.

EGWWS is a capital-intensive sector with a tight labour market of employees with higher skill and higher wages than most other sectors. Approximately 50% of our workforce are electrical engineers and field staff working on electrical assets. There is also a strong union presence, with around 38% of the workforce under collective agreements. As such, labour price growth in the EGWWS WPI is consistently higher compared to the 'all industry' average WPI.

Demand for skilled labour in the electricity sub-sector is growing at a faster rate compared to the remainder of the EGWWS sector (and compared to the remainder of the economy), as the number and type of services available increases with a transition to renewables and distributed energy resources (**DER**). Comparatively, Gas, Water and Waste sectors are stable. Industry wage data for 2016–2017 from the ABS shows that average wage levels in the electricity sub-sector are more than 50% higher than employees in the waste sub-sector and 40% higher than those in the water and sewerage sub-sector. As such, the EGWWS WPI forecast is likely to underestimate the labour price growth for the electricity distribution sector alone.

Overall, we expect the labour market for skilled labour will tighten further during the 2021–2026 period, limiting our ability to negotiate wages, particularly under collective bargaining. The BIS Oxford forecast of the EGWWS WPI reflects a realistic expectation of labour price growth for an efficient, prudent and realistic operating expenditure forecast for the electricity distribution sector.

Detailed information on drivers of the Victorian EGWWS WPI, comparisons to other industries and jurisdictions, and assessment of forecasting accuracy is available in BIS Oxford's and Frontier's reports.[146]

Labour and non-labours weights

To develop our real price forecast we assigned weights to the price of labour and non-labour that reflect our efficient mix of labour and non-labour inputs. We propose to use our historical average revealed input mix to define labour and non-labour weights used for forecasting real price growth in 2021–2026, as shown in table 9.7.

Table 9.7 Labour and materials input weights in forecasting real price growth (%)

Input	2021/22	2022/23	2023/24	2024/25	2025/26	2021–2026 average
Labour	77	77	77	77	77	77
Non-labour	23	23	23	23	23	23

Source: Powercor

Using efficient revealed cost is the most prudent and realistic approach to forecasting future cost. Consistent with its expenditure forecast assessment guideline, the AER accepts the base year revealed operating expenditure as the starting point for forecasting allowances unless its benchmarking analysis identifies that level of operating expenditure to be 'materially inefficient'. Each efficient distributor's revealed operating expenditure in the base year reflects its operating environment, which results in a unique input mix on the productivity

146 PAL ATT014: BIS Oxford, *Labour escalation*, April 2019; PAL ATT053: Frontier, *Review of labour escalation*, December 2019.

frontier. If the AER allows the revealed cost base year but not the corresponding efficient input mix, it will either overcompensate or undercompensate efficient distributors.

The AER's incentive-based regulatory framework incentivises an efficient input mix, which will vary by distributor depending on its operating environment. The efficiency benefit sharing scheme (**EBSS**) incentivises distributors to reduce total operating expenditure and there is a reputational incentive to improve benchmarking performance. If we were to increase expenditure by maintaining an inefficient input mix, we would forgo EBSS rewards and reputational advantage from improved benchmarking results. We will therefore always seek an efficient input mix that maximises EBSS rewards and reputational advantage.

We propose to use an average of our actual efficient input mix over the 2014–2018 period to determine the labour and non-labour weights. Using a five-year average further addresses the AER's concern we would adjust our input mix inefficiently in the base year to favour one input over another. Our input mix over 2014–2018 reflects an efficient, prudent and realistic basis for the forecast of our input mix for 2021–2026.

The AER's preferred approach to forecasting real price growth is to apply an industry average input weight to all distributors. We engaged Frontier to assess the appropriateness of using industry average input weights for forecasting labour price growth for efficient distributors. For the following reasons, Frontier found there is no sound basis for the AER to apply industry average input weights to all distributors when setting operating expenditure allowances, rather than the actual input weights of individual distributors:

- adoption of actual input weights is unlikely to weaken efficiency incentives
- the AER’s approach has not been assessed for prudency and realism and is therefore not consistent with the operating expenditure objectives
- the AER uses revealed historical costs to set future allowances in some circumstances and it is unclear why the same approach cannot be taken for labour and non-labour weights
- contrary to the AER's claim that using a revealed input mix in setting allowances and an industry average in benchmarking would result in some distributors being found efficient with one measure and inefficient with another, the AER’s benchmarking analysis is not materially sensitive to the use of actual input weights.

Using revealed input weights also removes the potential for errors in the calculation of industry averages, or basing the calculations on incomplete data sets, which can lead to inefficient allowances. In its assessment, Frontier found the input weights used by the AER in recent decisions to be unreliable for setting allowances. Frontier found evidence that:

- the data relied upon by the AER to calculate industry average input weights have not been reported consistently by distributors, including a significant number of missing data points, and the AER appears to have undertaken no due diligence to identify this
- there are major shortcomings in the methodology used by the AER to calculate industry average input weights, including:
  - the historical time period the average input weights relate to represents a period of very material cost restructuring for some distributors which may never be repeated
  - the AER has applied an inappropriate ‘rule-of-thumb’ to fill in missing/unreported data
  - average cost shares are biased towards large distributors and distributors that report data across all categories
- the AER’s calculations appear to contain some errors.

Frontier concludes the AER’s current estimate of input weights should not be used to set operating allowances for distributors. Conversely, our revealed input mix is audited and efficient.

Frontier's findings are available in its report attached to this regulatory proposal.[147]

9.2.5 Forecast output growth

We forecast growth in outputs to capture increases in operating expenditure which are driven by changes in the size of the network and the quantity of services we will supply over the 2021–2026 regulatory period.

To forecast output growth, we:

- model and test various output measures as drivers of operating expenditure
- determine the significant output measures and their weights
- forecast a growth rate for each selected output measure.

Selecting output measures and their weights

To model, test and select appropriate expenditure drivers and their weights, we assessed the models used in AER's benchmarking report, prepared by Economic Insights. Economic Insights prepares four models for the AER:[148]

- Cobb-Douglas Stochastic Frontier Analysis (**SFA**) (econometric model)
- Cobb-Douglas Least Squares (**LS**) (econometric model)
- Translog (**TL**) LS (econometric model)
- Multilateral Partial Factor Productivity (**MPFP**) (non-parametric model).

We engaged NERA Economic Consulting (**NERA**) and Frontier to independently assess the most appropriate models to help determine the weights of each output measure. Both NERA and Frontier found that, while there were challenges with each model, the average of two Cobb-Douglas models—SFA and LS—was the most appropriate estimate of weights for use in forecasting output growth.[149]

<u>MPFP is not an appropriate model for forecasting output growth</u>

NERA found the MPFP is an unreliable measure of drivers of cost of an efficient operator for the following reasons:

- the process for deriving weights from the MPFP modelling is not transparent
- the drivers included in the MPFP modelling were chosen based on tariff structure, not by assessing their effect on distributors' costs
- the weights in the MPFP model are artificially constrained to be positive, masking possible misspecification of the model

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[147] PAL ATT013: Frontier, *Review of output growth estimation*, December 2019.

[148] In the AER's 2019 Annual Benchmarking Report published in November 2019, it also introduced a fifth model Translog SFA.

[149] PAL ATT012: NERA, R*eview of the AER’s Proposed Output Weightings Prepared for CitiPower, Powercor, United Energy and SA Power Networks*, December 2018; PAL ATT052: Frontier*, Review Of Econometric Models Used By The AER To Estimate Output Growth A Report Prepared For Citipower, Powercor And United Energy*, December 2019.

- the MPFP weights are estimated with very little data, suggesting the weights are estimated imprecisely.

Frontier agreed with NERA that the AER should discontinue its reliance on the Leontief model (used in MPFP) in the setting of operating expenditure allowances. Frontier came to this conclusion due to severe statistical problems associated with the models estimated by Economic Insights and the multicollinearity between the customer numbers, circuit length and the time trend in the estimating equations.

Frontier also found that based on the statistical evidence, energy throughput is not a material driver of operating expenditure. Their review of the statistical properties of Leontief cost functions estimated by Economic Insights for the Annual Benchmarking Report found no statistical evidence that energy throughput has material impact on operating expenditure.

According to the MPFP model, operating expenditure would decrease with falling energy throughput. This is an inaccurate and misleading representation of actual cost drivers. In fact, the relationship between energy throughput and operating expenditure is likely to be increasingly negative—as the growth in DER reduces energy throughput it also imposes additional distribution costs that are not captured by customer numbers and ratcheted maximum demand.

In its 2019 Benchmarking Report, the AER acknowledged the possibility of the energy throughput measure undercompensating distributors for actual costs:[150]

> *Currently, the energy throughput output variable captures changes in the amount energy delivered to customers over the distribution network as measured at the customer meter. It does not measure energy delivered into the distribution network via distributed energy resources, such as from residential roof-top solar panels. In the extreme, an increase in rooftop solar panels could potentially involve a substitution of different energy sources amongst the same customers without changing the total energy consumed or materially changing the existing network in terms of circuit length or maximum demand. However, a distributor may be required to incur higher opex and/or capital to manage the safety and reliability of its network. In this situation there could be a material increase in inputs without a corresponding increase in any or all of the output measures.*

Given analysis from NERA and Frontier, we have excluded the MPFP model from our output growth forecast.

<u>Translog models are not appropriate for forecasting output growth</u>

Frontier also found the translog cost function should only be considered for determining output weights if translog-derived weights are evaluated at output levels that are relevant to the Australian distributors. The approach adopted by the AER is to evaluate the elasticities from the model at the average output levels of all distributors in the international sample. However, these average output levels are vastly different to the output levels of Australian distributors. The elasticities should be evaluated at output levels that are reflective of the operating characteristics of the Australian distributors. However, Frontier concludes if the AER believes that the elasticities are constant across all utilities in the sample, then it would be statistically more efficient to estimate these constant elasticities using the Cobb-Douglas cost function.

We are therefore satisfied our approach to forecasting output growth, using an average of the Cobb-Douglas SFA and LS models, results in more efficient, prudent and realistic operating expenditure forecasts compared to the use of the simple average of the four models.

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150 PAL ATT045: Australian Energy Regulator, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2019, pp. 48-49.

Our proposed forecast output growth uses the output measures from the two models—customer numbers, ratcheted maximum demand and circuit length—and set the weights for each output measure as the average of the weights produced by the two models. Table 9.8 demonstrates the output measures and the weights we used in forecasting output growth.

Table 9.8 Output measures and weights used in forecasting output growth (%)

Output measure	Cobb-Douglas SFA	Cobb-Douglas LS	Average of SFA and LS
Customer numbers	70.80	67.59	69.20
Circuit length	16.81	11.78	14.30
Ratcheted maximum demand	12.39	20.63	16.51

Source: NERA Economic Consulting

Further information on NERA's and Frontier's assessments on appropriate output growth is available in their reports attached to this regulatory proposal.[151]

Forecasting growth in each output measure

We engaged the Centre of International Economics (**CIE**) to independently develop customer number and maximum demand forecasts.[152] We have used the 2014–2018 historical average to forecast circuit length growth. Their forecasts are shown in table 9.9.

Table 9.9 Forecast growth for output measures (%)

Measure	2021/22	2022/23	2023/24	2024/25	2025/26	2021–2026 average
Customer numbers	2.2	2.1	2.1	2.0	2.0	2.1
Circuit length	0.6	0.6	0.6	0.7	0.7	0.6
Ratcheted maximum demand	3.5	1.6	1.6	1.4	1.8	2.0

Source: PAL MOD 9.02 - Rate of change - Jan2020 – Public; PAL ATT019: CIE, *Customer number forecasts*, May 2019; PAL ATT022: CIE, *Maximum demand forecasting*, March 2019.

Table 9.10 shows our forecast output growth, as a sum–product of the forecast growth rate of each output measure and the weight of each measure.

151 PAL ATT012: NERA, R*eview of the AER's Proposed Output Weightings Prepared for CitiPower, Powercor, United Energy and SA Power Networks*, December 2018; PAL ATT052: Frontier*, Review Of Econometric Models Used By The AER To Estimate Output Growth A Report Prepared For Citipower, Powercor And United Energy*, December 2019.

152 PAL ATT019: CIE, *Customer number forecasts*, May 2019; PAL ATT022: CIE, *Maximum demand forecasting*, March 2019.

Table 9.10 Forecast output growth rate (%)

Measure	2021/22	2022/23	2023/24	2024/25	2025/26	2021–2026 average
Output growth	2.2	1.8	1.8	1.8	1.8	1.9

Source: Powercor

Our approach to customer number and maximum demand forecasts, including forecasts of solar penetration, batteries and electric vehicles and their impact on maximum demand, is outlined in the Appendix.[153]

9.2.6 Productivity growth

We have applied the AER's productivity adjustment in accordance with the AER's final decision on 'Forecasting productivity growth for electricity distributors', as shown in table 9.11. However, as an efficiency frontier network, we have already achieved considerable productivity improvements through investment in new technologies and changes in operating practices, and have limited capacity to achieve the 0.5% productivity adjustment through business as usual activities during the 2021–2026 regulatory period.

Table 9.11 Forecast operating expenditure productivity (%)

	2021/22	2022/23	2023/24	2024/25	2025/26
Forecast productivity	0.5	0.5	0.5	0.5	0.5

Source: Powercor

Shifting the productivity frontier requires investment in innovative technology and practices

In its March 2019 final decision on 'Forecasting productivity growth for electricity distributors', the AER determined 0.5% per year reflects the best estimate of the operating expenditure productivity growth that an electricity distributor on the efficiency frontier should be able to achieve going forward. The AER stated this can come from new technology, changes to management practices and other factors that contribute to improved productivity within the industry over time.

We are one of the four networks on the efficiency frontier in the Australian electricity distribution sector. In its 2019 Benchmarking Report the AER stated:[154]

> *CitiPower, Powercor, United Energy and SA Power Networks have consistently been the most efficient distribution service providers in the NEM. These networks are amongst those service providers that are on the productivity frontier.*

By virtue of being an efficiency frontier network, we have limited capacity to achieve productivity gains through business as usual. This places us in a uniquely challenging position compared with other networks that will more easily achieve the 0.5% per annum productivity through effectively catching-up to the efficiency frontier.

To achieve the 0.5% productivity adjustments, we would need to invest in innovative new technologies which materially change operational processes. This will be challenging given we have already revolutionised a

153 PAL APP03: Powercor, *Maximum demand and customers*, January 2020.

154 PAL ATT045: Australian Energy Regulator, *2019 Benchmarking Report*, November 2019, p.18.

significant portion of our operations through automation and innovation. At this point in time we cannot envisage how we would achieve the full 0.5% productivity adjustment.

We have proposed two ICT projects that are driven by customer benefits, customer enablement and intelligent engineering, which also have a modest expectation of operating expenditure benefits.[155] We consider these projects will only marginally contribute towards our ambitious target of 0.5% operating expenditure savings per annum during 2021–2026.

In its ICT Guideline the AER states:[156]

> *non-recurrent ICT capex projects where the main driver are operating expenditure benefits should include a negative operating expenditure step change to at least the same of the cost of those capital expenditure projects, with any additional benefit above this negative step change may contribute to the 0.5% operating expenditure productivity assumption*

We disagree the 0.5% productivity assumption can be reached without funding for capital expenditure required to achieve the savings. In forecasting the 0.5% pre-emptive productivity adjustment, the AER relied on evidence that included productivity growth attributable to non-recurrent ICT expenditure. If the AER makes a further adjustment to reduce allowed operating expenditure to reflect productivity that is expected to result from non-recurrent ICT expenditure, this will result in over-estimation of the forecast productivity growth rate and an operating expenditure allowance below efficient and prudent costs.

It is particularly important to acknowledge the expenditure necessary to achieve future savings for efficient frontier networks. We have already automated our processes and in doing so, have de-risked the industry with regard to new and innovative ICT by introducing it to the Australian energy market. We have lean operations and do not have the contingency to absorb further risky and costly initiatives without reasonable reward. We can only envisage future savings coming from investment in new and risky technology—we therefore consider it crucial we receive sufficient funding for the productivity-enhancing projects to allow us to achieve the operating expenditure objectives.

Relationship between productivity and step changes for regulatory obligations

The AER's decision to apply a 0.5% per year pre-emptive productivity adjustment is a shift from its previous approach of applying a 0% productivity adjustment at a time of negative measured productivity. In the past, the AER has never compensated distributors for growing cost pressures through the productivity adjustment (i.e. allowing distributors to recover more allowance by applying an adjustment for negative productivity). Rather, the AER compensated distributors for negative productivity by allowing step changes related to new or growing regulatory obligations.

According to the AER's final decision, the period of growing regulatory obligations ended between 2011 and 2012 on average across Australia. As a result, the AER based its new approach to measuring productivity on electricity distribution data post-2011. This approach was applied to econometric models as well as the MPFP model.

The AER's measure of electricity distribution productivity during 2011–2017 removes the impact of regulatory obligations on operating expenditure productivity by assuming minimal or no growth in obligations during that period. By virtue, any change in regulatory obligations should be considered in isolation of measured productivity, whether historically or forecast. This is consistent with the AER's previous approach to measuring

155 PAL BUS 7.02: Powercor, *Customer enablement*, January 2020; PAL BUS 7.07: Powercor, *Intelligent engineering,* January 2020.

156 PAL ATT164: Australian Energy Regulator, *Non-network ICT capex assessment approach*, November 2019, p.12.

productivity where distributors were compensated for growing regulatory obligations through step changes and not through a productivity adjustment.

By isolating the impact of regulatory obligations on productivity, the 'rate of change' calculation for forecasting operating expenditure does not account for change in regulatory obligations. To ensure we are able to achieve our operating expenditure objective of the Rules, the AER must allow step changes for regulatory obligations during 2021–2026.

We are maintaining affordability by keeping our prices low

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10 Revenue

Summary

We will reduce our charges for residential and small business customers over the 2021–2026 regulatory period. This reflects the efficiencies we will deliver to customers, such as through our new ICT initiatives and lower borrowing costs.

We have also applied the rate of return consistent with the AER's guideline.

We propose to apply the following incentive schemes to ensure we face the right incentives to continue to drive efficiencies—efficiency benefit sharing scheme, capital expenditure sharing scheme, demand management incentive scheme and innovation allowance, service target performance incentive scheme and the F-factor scheme.

10.1 What we plan to deliver

The revenue we propose to recover from our customers, and the affordability we strive to deliver, are key concepts we have sought to balance in our regulatory proposal. As discussed in our respective capital and operating expenditure chapters, we have considered whether the programs we intend to deliver are needed, will result in customer benefits, and are delivered in the least-cost way. Importantly, we have also considered whether in totality this proposal delivers the affordability outcomes our customers are seeking.

Stakeholder feedback

Throughout our research, the affordability of energy has been 'top of mind' for our customers and stakeholders. Customers have made it very clear they want a resilient and flexible network but also one that is affordable. Only a third of customers felt electricity is affordable, with a fifth of all customers finding it very expensive. For our commercial and industrial customers, energy affordability is seen as a key factor in the success of large businesses and the likelihood of these businesses staying in Australia or moving offshore.

Overwhelmingly, customers want us to provide value for money rather than reduce services to increase price cuts:

> *'Value for money – if I am paying I expect it to be reliable. Expect it to work when I flick the switch. I agree with those values.'*
>
> *'Want to find a good balance between investment and affordability.'*

Our proposal provides value for money for customers—we will continue to run one of the most reliable networks in the country at affordable prices while meeting new challenges and regulatory obligations. We will also deliver new customer benefits and cost savings to our customers while improving productivity and continuing to shift the yard-stick of efficiency in the industry.

Consistent with our stakeholder feedback, we will reduce our charges for residential and small business customers over the 2021–2026 regulatory period, compared to the current period. The average estimated bill impact is outlined in table 10.1.[157]

Table 10.1 Average bill impact ($)

Type	Average estimated bill impact
Residential	-24
Small business	-68

Source: Powercor

[157] This comparison is based on 2020 charges compared to average charges over the 2021–2026 regulatory period. For simplicity, it excludes the transitional six month period. It includes the impact of metering. It includes the impact of metering. More information on the transitional period is available in PAL APP07: Powercor, *Transitional arrangements 1 January to 30 June 2021*, January 2020.

We note the final impact to customers will depend on factors such as the willingness of electricity retailers to reflect our price reductions in their pricing, actual energy consumption and the impacts of incentive schemes.

With respect to our charging structures, we are proposing changes to residential and small business structures to accelerate the pace of reform without jeopardising the stakeholder support that is crucial to enable change. We will introduce a new two-rate tariff for new customer connections, customers seeking supply upgrades to three-phase and customers installing solar or batteries. The objective is to encourage customers to move discretionary electricity use into off-peak periods, when the network is under less pressure. Feedback from our customers strongly preferred the simplicity of a two-rate tariff. Further information on our pricing structures is available in our tariff structure statement attachments.[158]

To achieve our forecast price reductions, we are keeping the total revenue we will recover from our customers flat compared to the 2016–2020 regulatory period. We are able to constrain our revenue requirement while providing more services through the range of activities discussed below.

10.1.1 We have created efficiencies for our customers and responded to incentives

We have a strong track record of responding to the AER's incentive framework to reduce costs. This is important because when we reduce our costs, customers receive 70% of these savings through lowering the revenue we recover, and hence customer bills. Table 10.2 outlines the efficiencies we have made over the 2016–2020 regulatory period.

Table 10.2 Efficiencies over the 2016–2020 regulatory period ($ million, 2021)

Investment type	Efficiencies
Capital	334
Operating	132
Total	**466**

Source: Powercor

The specific actions we undertook over 2016–2020 to deliver savings to our customers included:

- automated, centralised and optimised works scheduling, remote crew dispatch, live on-site reporting of works and live fault monitoring
- re-negotiated contracts with service providers
- restructured corporate and network management services
- leveraged smart meter data to better manage the network and reduce capital expenditure
- deferred transformer replacement projects through the introduction of risk monetisation and calibration of our condition based risk model to take account of recent performance of comparable assets

[158] PAL APP05: Powercor, *Tariff structure statement*, January 2020. PAL APP06: Powercor, *Tariff structure statement reasons document*, January 2020. PAL ATT032: Powercor, *Indicative tariffs*, January 2020.

- not proceeded with upgrading our billing system as a result of the Victorian Government's decision to only allow opt-in demand tariffs (which diluted the customer benefits case), and the future opportunity to consider migrating to United Energy's system.

It is through implementing these types of initiates that we consistently rank among the lowest cost distribution networks in Australia. However, as is the nature of continuous improvement, it is becoming increasingly difficult to find these efficiencies—the majority of our transformation programs over the 2016–2020 regulatory period are not repeatable.

To continue to driving efficiency, we will need to consider more innovative and risky ICT solutions in the future. For the 2021–2026 regulatory period, we have included a number of these initiatives and reduced our expenditure forecasts to reflect this. This means customers will receive these savings quicker.

More information on how we have delivered customer savings, and their impact on the operation of the incentives schemes, is included in an appendix to this proposal.[159]

10.1.2 We are responding to lower borrowing costs

The rate of return set by the AER seeks to reflect the cost of funds required by an efficient entity to fund network investment. The rate of return set by the AER has decreased relative to our 2016–2020 regulatory period, and all things being equal, this reduces revenues.

We have applied the AER's rate of return instrument in developing our regulatory proposal, and will seek to reduce our business costs accordingly.

We also recognise the impact of depreciation on long-term prices. As outlined in section 10.2.2, we will accelerate the deprecation of selected assets that will be removed from our network in the 2021–2026 regulatory period due to technical obsolescence. While this approach reflects common regulatory and accounting practice, accelerating depreciation while borrowing costs are low is akin to paying off more of a home loan when interest rates are low. The benefits of this include the following:

- it is possible to reduce the size of the loan (or RAB) without increasing overall prices
- when borrowing rates increase, there is less mortgage (or RAB) to be paid.

10.2 Our forecasting approach

This section sets our forecast approach for the development of our revenue requirement over the 2021–2026 regulatory period for standard control services.[160] This includes the building block approach required by the Rules, our use of the AER's roll forward model (**RFM**) and post-tax revenue model (**PTRM**), and the application of various incentive schemes for the current and future regulatory period. We have prepared our regulatory proposal in accordance with our proposed cost allocation method.[161]

In general, we have adopted the standard approach outlined by the AER for previous regulatory decisions. A summary of our forecast revenue requirements is shown in table 10.3. As outlined above, our proposed X factors have been calculated to hold expected smoothed revenue constant in real terms over the regulatory period.

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159 PAL APP02: Powercor, *What we have delivered*, January 2020.

160 We have classified our services in accordance with the AER's framework and approach paper published in January 2019.

161 PA ATT027: Powercor, *Cost Allocation Method*, January 2020.

Table 10.3 Revenue requirement ($ million, nominal)

Building blocks	2021/22	2022/23	2023/24	2024/25	2025/26
Return on assets	218.9	231.6	242.4	248.1	251.1
Regulatory depreciation	131.6	142.2	155.6	159.5	171.0
Operating expenditure	314.8	310.4	327.4	341.0	358.5
EBSS	8.0	-0.6	-4.4	-3.6	-
CESS	15.9	16.3	16.7	17.1	17.5
Other adjustments	0.7	0.7	0.8	0.8	0.8
Corporate income tax	3.3	-	-	-	-
Unsmoothed revenue requirement	693.2	700.6	738.5	762.8	798.9
Smoothed revenue requirement	703.4	720.3	737.5	755.2	773.4
Forecast CPI (%)	2.4	2.4	2.4	2.4	2.4
Revenue X factor (%)	**0.1**	**-**	**-**	**-**	**-**

Source: Powercor
Notes: A positive revenue X factor means a real revenue decrease and a negative revenue X factor means a real revenue increase.

10.2.1 Roll forward of the RAB

We have used the AER's RFM to calculate the opening RAB from 1 July 2021:

- capital expenditure rolled into the RAB has been reduced by customer contributions and disposals
- net capital expenditure includes a half year’s weighted average cost of capital (**WACC**)
- straight-line depreciation based on forecast capital expenditure has been deducted in accordance with the AER’s 2016–2020 final determination
- the RAB has been adjusted for actual inflation, consistent with the method used for the indexation of the control mechanism.

The estimated opening value of the RAB for standard control services as at 1 July 2021 is shown in table 10.4, and in our attached RFM.[162]

[162] A positive revenue X factor means a real revenue decrease and a negative revenue X factor means a real revenue increase.

Table 10.4 Roll forward of the RAB from 1 January 2016 to 1 July 2021 ($ million, nominal)

Description	Total
1 January 2016 opening RAB from previous determination	3,307
Add: True-up for 2015 capital expenditure	-4
Add: Actual/estimated net capital expenditure for 2016–2021 (including half-year WACC)	2,037
Less: Forecast straight-line depreciation for 2016–2021	-1,111
Add: Adjustment for actual inflation for 2016–2021	345
1 July 2021 opening RAB	**4,573**

Source: Powercor

To roll forward the RAB from 2021 to 2026, we have applied the following approach:

- the RAB has been rolled forward from 2021 to 2026 in accordance with the Rules using the AER's PTRM
- forecast net capital expenditure for the roll forward of the RAB over the 2021–2026 regulatory period has been reduced by forecast customer contributions and by forecast disposals
- forecast net capital expenditure includes a half year's WACC.

The roll forward of the RAB is shown in table 10.5, and in our attached PTRM.[163]

Table 10.5 Roll forward of the RAB over 2021–2026 ($ million, nominal)

Description	2021/22	2022/23	2023/24	2024/25	2025/26
Opening RAB	4,573	4,978	5,363	5,653	5,902
Forecast net capital expenditure	537	527	446	408	394
Depreciation	-241	-262	-284	-295	-313
Inflation on opening RAB	110	119	129	136	142
Closing RAB	**4,978**	**5,363**	**5,653**	**5,902**	**6,124**

Source: Powercor

10.2.2 Regulatory depreciation

Straight-line depreciation has been calculated using year-by-year asset tracking from 2011, consistent with the approach taken in the AER's 2016–2020 final determination (and shown in the attached depreciation model).[164] Our proposed standard asset lives are shown in table 10.6.

163 PAL MOD 10.02 - PTRM 2021-26 - Jan2020 - Public.

164 PAL MOD 10.03 - Depreciation 2021-26 - Jan2020 Public.

Table 10.6 Standard and remaining asset lives (years)

Asset	Standard life
Sub-transmission	50
Distribution system assets	51
SCADA/network control	13
Non-network general assets: IT	6
Non-network general assets: other	15
VBRC	25.6
In-house software	5
Equity raising costs	42

Source: Powercor

We have also separated asset classes covering assets that will become redundant before 2026, so that they receive the appropriate economic lives. These asset classes are outlined below, and further information is available in our depreciation model.[165]

Automatic circuit reclosers

As part of our tranche one and two contingent project applications, the AER approved the accelerated depreciation for RVE and VWVE type automatic circuit reclosers (**ACRs**) that did not meet our REFCL technical installation standards.

Given our smart ACR program (discussed in section 4.1.3 and in our attached business case), we are now replacing all ACRs in our REFCL network with smart ACRs.[166] As such, the accelerated depreciation in our regulatory proposal includes the following:

- all ACRs for tranche three sites, and our Waurn Ponds and Corio supply areas (as these were not included with our previously approved continent project applications)
- all non-RVE and VWVE type ACRs for tranche one and two sites.

Our forecast method for calculating the depreciable value is based on our standard distribution asset lives, the actual asset remaining life, and the replacement value assumptions used in our REFCL cost models.

Surge arrestors

As part of our tranche one and two contingent project applications, the AER approved accelerated depreciation for surge arrestor types that did not meet our REFCL technical installation standards. Our depreciation value for the 2021–2026 regulatory period includes the remaining surge arrestor replacements required for our tranche three REFCL sites, and our Waurn Ponds and Corio supply areas.

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[165] PAL MOD 10.03 - Depreciation 2021-26 - Jan2020 Public.

[166] PAL BUS 4.05: Powercor, *Mitigation REFCL reliability impacts*, January 2020.

Our forecast method for calculating the depreciable value is consistent with that previously accepted by the AER (i.e. based on our standard distribution asset lives, the average remaining life of the relevant surge arrestor population, and the replacement value assumptions used in our REFCL cost models).

Underground cable

Underground cable will be replaced as part of the installation and operation of REFCLs on our network. Specifically, we are proactively replacing all steam-cured XLPE cable that was installed prior to 1989, as in the presence of higher voltages from the REFCL, excessive water treeing can occur resulting in failure of the cable.

We did not seek to accelerate the depreciation of underground cable in our contingent project applications for tranches one and two, due to limited available information at the time. Therefore, the depreciable value included in our 2021–2026 regulatory period captures all underground cable that has or will be replaced through the REFCL program.

Our forecast method for calculating the depreciable value is based on our standard distribution asset lives, the age profile of all underground cable in REFCL areas with reference to the volume by installed year, and the replacement value assumptions used in our REFCL cost models.

Other non-REFCL assets

In addition to the REFCL-driven replacements, we are also accelerating the deprecation for the following:

- replacement of distribution transformers to enable greater capacity of solar generation on our networks by 2026. The replacement on distribution transformers is to remove old models that do not have appropriate tapping functionality and/or to increase the transformer capacity
- twisted PVC grey service cables which will be replaced by 2026. Due to safety concerns associated with the cables, a proactive program has commenced to replace cables that pose a risk to the community and this program will continue through the 2021–2026 regulatory period
- high voltage aerial bundled cable in low bushfire risk areas which will be replaced by 2026.

A summary of our total regulatory depreciation for each year of the 2021–2026 regulatory period is shown in table 10.7.

Table 10.7 Regulatory depreciation ($ million, nominal)

Description	2021/22	2022/23	2023/24	2024/25	2025/26
Straight-line depreciation	241.3	261.7	284.3	295.2	312.6
Less: Inflation adjustment	109.8	119.5	128.7	135.7	141.6
Regulatory depreciation	**131.6**	**142.2**	**155.6**	**159.5**	**171.0**

Source: Powercor

10.2.3 Rate of return

Our rate of return has been prepared consistently with the AER's 2018 rate of return instrument (**2018 RORI**), modified in accordance with AER's instructions to accommodate the Victorian Government's intent to extend the current regulatory period by six months. Our placeholder rate of return is shown in table 10.8.

Table 10.8 Placeholder rate of return

Description	2021/22	2022/23	2023/24	2024/25	2025/26	Average
Nominal risk free rate (%)	1.32	1.32	1.32	1.32	1.32	1.32
Market risk premium (%)	6.10	6.10	6.10	6.10	6.10	6.10
Equity beta	0.6	0.6	0.6	0.6	0.6	0.6
Return on equity (%)	4.98	4.98	4.98	4.98	4.98	4.98
Return on debt (%)	4.65	4.43	4.21	3.99	3.77	4.21
Gearing (%)	60	60	60	60	60	60
Nominal rate of return (%)	**4.79**	**4.65**	**4.52**	**4.39**	**4.26**	**4.52**

Source: Powercor

Return on debt

The 2018 RORI requires the return on debt to be calculated as a ten-year trailing average, updated annually. The AER has provided us with modified weightings to be used to accommodate the six-month extension to the current regulatory period.

We estimate the ten-year trailing average annual return on debt based on the placeholder averaging period of the last 20 business days in July 2019.

The 10 year trailing average debt rates will be updated in accordance with the 2018 RORI based on observations during the agreed risk-free rate averaging periods.

Return on equity

Under the 2018 RORI, the return on equity must be calculated as the risk-free rate, plus a market risk premium multiplied by an equity beta. The risk-free rate must be calculated as the 10 year yield to maturity on Commonwealth Government Securities, measured over the agreed risk-free rate averaging period.

We have calculated the return on equity using a placeholder risk free rate of 1.32%, based on the placeholder averaging period of the last 20 business days in July 2019. The risk-free rate will be updated based on observations during the agreed risk-free rate averaging period.

Averaging periods

The 2018 RORI proposes there be an averaging period set for each year of the relevant regulatory period from which the data for the allowed return on debt will be drawn, and a single averaging period from which risk-free rate data for the allowed return on equity will be drawn.

The 2018 RORI states we can propose the period no later than the lodgement date of the regulatory proposal, and agreed by the AER on a confidential basis. We have proposed our averaging periods confidentially to the AER.

10.2.4 Expected inflation

In the PTRM, the AER specifies a methodology to estimate inflation. The method is to calculate the geometric average based on the inflation forecasts for two years sourced from the latest available Reserve Bank of

Australia's (**RBA**) statement of monetary policy and the mid-point of the RBA's target inflation band for eight years.

Our estimate of expected inflation, for the purposes of a placeholder for our regulatory proposal, is 2.40%. Using the PTRM method, this assumes an RBA inflation forecast of 2.00% for the first two years and 2.50% for the remaining eight years.

Recent concerns have been raised with the AER about the current PTRM method, and potentially the inflation framework. Based on the AER's consideration of these concerns, we may amend the method used to calculate expected inflation in our revised proposal.

10.2.5 Debt raising costs

Debt raising costs are transaction costs incurred each time debt is raised or refinanced. These costs may include arrangement fees, legal fees, company credit rating fees and other transaction costs.

There is now some uncertainty associated with debt raising costs for the following reasons:

- in the SA Power Networks draft decision, the AER based the debt raising cost allowance on a report from Chairmont which updated the estimate previously provided by PwC in 2013. SA Power Networks have submitted a report from CEG to the AER in response to its draft decision which contends that one component of debt raising costs—arranger fees—should be 6.88 basis points per annum (**bppa**) rather than the 3.97 bppa calculated by Chairmont and adopted in the AER draft decision.
- the AER collected actual debt raising cost information from all regulated networks in November 2019, but it is not yet clear whether consideration of this data will result in the AER modifying its debt raising cost estimates or approach.

We have applied a placeholder debt raising cost of 8 bppa. We intend to respond to the AER's draft decision on our proposal, at which time the AER will have had the opportunity to consider networks' debt raising data collected. They will also have had the opportunity to consider the CEG report submitted by SAPN in their revised regulatory proposal.

The interest rate swaps which we currently have in place mature at the end of each calendar year over the next ten years. Due to the transition from calendar to financial regulatory years, there will be a mismatch between the maturity date of each existing interest rate swap over the next ten years and the commencement date for rates that need to be hedged in the future. The most efficient solution for dealing with this mismatch depends on many factors including the shape of the yield curve. It is premature for us to select a solution prior to the submission of this proposal and therefore we have not yet been able to cost a solution. Should the efficient cost be material, we will propose a cost in the revised proposal.

10.2.6 Equity raising costs

Equity raising costs are transaction costs incurred when a network raises new equity to fund capital investment. The AER provides a benchmark allowance to recover an efficient amount of equity raising costs, when a network's capital expenditure forecast requires an equity injection to maintain the benchmark gearing of 60%.

Our calculation of equity raising costs is contained in the PTRM.[167] This calculation includes the latest AER parameters, including an imputation credit distribution rate consistent with the 2018 RORI.

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[167] PAL MOD 10.02 - PTRM 2021-26 - Jan2020 - Public.

10.2.7 Shared asset revenue reduction

Shared assets are those used to provide both regulated and unregulated services. The AER may reduce our annual revenue requirement for a regulatory year to share unregulated revenue with customers. In making this decision, the AER must have regard to the shared asset principles and the Shared Asset Guideline.[168]

One of the shared asset principles is that a shared asset cost reduction should be applied where the use of the assets other than for standard control services is material. The AER's shared asset guideline outlines the use of shared asset is material when a distributor's annual unregulated revenue is expected to be greater than 1% of its total smoothed revenue requirement for a particular regulatory year. If this materiality threshold is exceeded, then 10% of forecast unregulated revenue earned from shared assets is deducted from the revenue building blocks and otherwise no shared asset revenue reduction applies.

Our shared asset revenue is primarily earned from renting poles and ducts to telecommunications companies. The calculation of materiality and shared asset revenue reduction for each year of the 2021–2026 regulatory period is shown in table 10.9.

Table 10.9 Shared asset revenue reduction ($ million, nominal)

Description	2021/22	2022/23	2023/24	2024/25	2025/26
Forecast unregulated revenue from shared assets	3.8	3.9	4.0	4.1	4.2
Smoothed revenue (prior to shared asset reduction)	703.4	720.3	737.5	755.2	773.4
Materiality percentage (%)	0.5	0.5	0.5	0.5	0.5
Shared asset revenue reduction	-	-	-	-	-

Source: Powercor

10.2.8 Estimated cost of corporate income tax

The estimated cost of corporate income tax for each year of the 2021–2026 regulatory period has been calculated using the AER's PTRM. The tax opening asset values, remaining lives and standard lives inputs for the PTRM have been calculated in the AER's RFM. The standard tax asset lives are consistent with Australian Tax Office rulings.

We have forecast immediately deductible capital expenditure based on the average actual amount of immediately deductible capital expenditure claimed over 2016–2018, as reported in the reset RIN. It is appropriate to use an average since the mix of capital expenditure can vary from year-to-year.

We have applied a value of 0.585 for the value of imputation credits consistent with the 2018 RORI. The estimated cost of corporate income tax is shown in table 10.10.

168 PAL ATT159: Australian Energy Regulator, *Shared Asset Guideline*, November 2013.

Table 10.10 Estimated cost of corporate income tax ($ million, nominal)

Description	2021/22	2022/23	2023/24	2024/25	2025/26
Estimated cost of corporate income tax	3.3	-	-	-	-

Source: Powercor

10.2.9 Incentive schemes

This section outlines the revenue increments and decrements arising from the incentive scheme that applied over the 2016–2020 regulatory period, as well as our application of these over the 2021–2026 regulatory period.

Efficiency benefit sharing scheme

The efficiency benefit sharing scheme (**EBSS**) provides incentives for us to drive efficiencies in operating expenditure. The benefits of efficiency savings are shared between us and our customers.

We have applied the AER's EBSS to calculate the revenue increments and decrements, as outlined in the attached model and in table 10.11.[169] In line with the EBSS guideline, debt raising costs, the demand management innovation allowance and GSLs have been excluded.

Table 10.11 EBSS calculation ($ million, 2021)

Description	2016	2017	2018	2019	2020
Adjusted benchmark EBSS operating expenditure	245.6	252.1	262.9	265.7	271.6
Actual EBSS operating expenditure	221.2	225.5	231.6	240.8	246.7
Incremental efficiency	14.6	2.2	4.8	-6.5	-
Carry-over year	2021/22	2022/23	2023/24	2024/25	2025/26
EBSS carryover	**7.8**	**-0.6**	**-4.1**	**-3.2**	**-**

Source: Powercor

We propose to continue to apply the EBSS to standard control operating expenditure over the 2021–2026 regulatory period to ensure we have strong incentives to pursue innovations which deliver lower costs to customers over the long term. We propose to continue applying the EBSS in accordance with the AER's EBSS guideline and exclude debt raising costs, demand management innovation allowance and GSL payments from the calculation of the 2021–2026 carryover.[170]

Applying the EBSS is consistent with the AER's framework and approach paper and our forecast operating expenditure for the 2021–2026 regulatory period, which is based on our actual efficient 2019 operating expenditure.

169 PAL RIN005 - Workbook 5 - EBSS - Jan2020 - Public.

170 These exclusions are consistent with the AER's 2016–2020 final determination for calculating the EBSS carryover.

Capital expenditure sharing scheme

The capital expenditure sharing scheme (**CESS**) provides financial rewards for distributors whose capital investments becomes more efficient and financial penalties for those that become less efficient. The scheme ensures savings are shared between customers and distributors.

We calculate the 2021–2026 CESS revenue increment or decrement as follows:

- calculate the cumulative underspend or overspend for the current regulatory period in net present value terms
- apply the network sharing ratio of 30% to the cumulative underspend or overspend to work out our share of the underspend or overspend
- deduct the 2016–2020 financing benefit or cost of the underspends or overspends.

We have identified projects deferred from the 2016–2020 regulatory period and reproposed for the 2021–2026 period, as outlined in the appendix to this proposal.[171] We have not adjusted the CESS calculation to exclude the deferred projects because these do not materially increase our capital expenditure forecasts.

The CESS outcome is shown in table 10.12 and more detail is available in the attached model.[172]

Table 10.12 CESS calculation ($ million, 2021)

Description	Present Value
Total efficiency gain	334.2
Network service provider share (30%)	100.2
Financing benefit	27.5
CESS payment in 2021–2026	**72.8**

Source: Powercor

Over the 2021–2026 regulatory period, we propose to continue applying the CESS to standard control expenditure in accordance with the AER's CESS guideline.[173] This ensures we have incentives to minimise project costs and pass on a proportion back to customers.

Consistent with the CESS guideline and the AER's framework and approach paper we propose using forecast depreciation to establish the opening RAB for the following regulatory period 2026–2031.

Demand management incentive scheme and allowance

The demand management incentive scheme (**DMIS**) and demand management innovation allowance (**DMIA**) mechanism provide incentives for us to explore demand management alternatives to network capital investment. We are provided with an annual fixed allowance in the form of additional revenue for each regulatory year of the regulatory period.

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171 PAL APP02: Powercor, *What we have delivered*, January 2020.

172 PAL RIN006 - Workbook 6 - CESS - Jan2020 - Public.

173 PAL ATT157: Australian Energy Regulator, *Capital Expenditure Incentives Guideline for Electricity Network Service Providers*, November 2013.

During the 2016–2020 regulatory period we commenced the following demand management initiatives:[174]

- we dynamically manage voltage levels on the network on peak demand days to manage supply imbalances in the wholesale energy market
- we are assessing the potential to partner with commercial customers to alleviate network constraints by reducing demand during peak periods and targeted load shedding.

We propose to apply the DMIS and DMIA in the 2021–2026 regulatory period. Applying these satisfies the requirements of the National Electricity Law (**NEL**) by providing an incentive to use more demand management, which can defer augmentation and create option value, potentially lowering costs in the long term.

In December 2017 the AER revised the way that the DMIA would be calculated, which is the sum of:

- $200,000 (in the dollars of the distributor's regulatory year that ends in 2017), escalated for inflation
- 0.075% of the distributor's annual revenue requirement.

Table 10.13 provides our proposed DMIA, calculated in accordance with the AER's guidelines.

Table 10.13 DMIA ($ million, 2021)

Description	2021/22	2022/23	2023/24	2024/25	2025/26
DMIA	0.7	0.7	0.7	0.7	0.7

Source: Powercor

Service target performance incentive scheme

The service target performance incentive scheme (**STPIS**) provides incentives for us to improve network reliability and customer service when the benefits exceed the costs.

Over the 2021–2026 regulatory period we propose calculating the STPIS targets, incentive rates and major event day (**MED**) threshold in accordance with the AER's 2018 STPIS guideline as follows:

- use historical performance data over the five-year period from 1 January 2015 to 31 December 2019[175]
- recast our historical data to align with the new definitions in the AER's distribution reliability measures guideline[176]
- apply the updated VCR as determined by the AER to determine the incentive rate[177]
- calculate the MED using a beta of 2.8 consistent with the 2016–2020 application of the scheme
- apply the revenue at risk of 0.5% in accordance with the guideline.

We do not propose to apply the GSL component of the STPIS scheme as we are subject to the Victorian jurisdictional GSL scheme.

Our proposed STPIS targets, incentive rates and MED threshold are set out in table 10.14.

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174 We did not seek a DMIA for these initiatives.

175 We have only used 2015-2018 audited data for the regulatory proposal. We will provide 2019 data and updated targets in April 2020.

176 PAL ATT155: Australian Energy Regulator, *Distribution Reliability Measures Guideline*, November 2018.

177 PAL ATT156: Australian Energy Regulator, *Value of Customer Reliability*, December 2019.

Table 10.14 STPIS targets and incentive rates for 2021–2026 regulatory period

STPIS parameter	Network segment	Target	Incentive rate (%)
Unplanned SAIDI	Urban	67.2	0.0329
	Rural short	99.6	0.0319
	Rural long	244.7	0.0212
Unplanned SAIFI	Urban	0.8	1.8377
	Rural short	1.1	1.9280
	Rural long	2.1	1.6743
MAIFIe	Urban	1.2	0.1470
	Rural short	2.6	0.1542
	Rural long	4.6	0.1339
Telephone answering (fault calls) (%)	Network	82.9%	-0.0400
MED threshold	Network	7.3	

Source: Powercor

More information is available in our incentives and targets models.[178]

Customer service incentive scheme

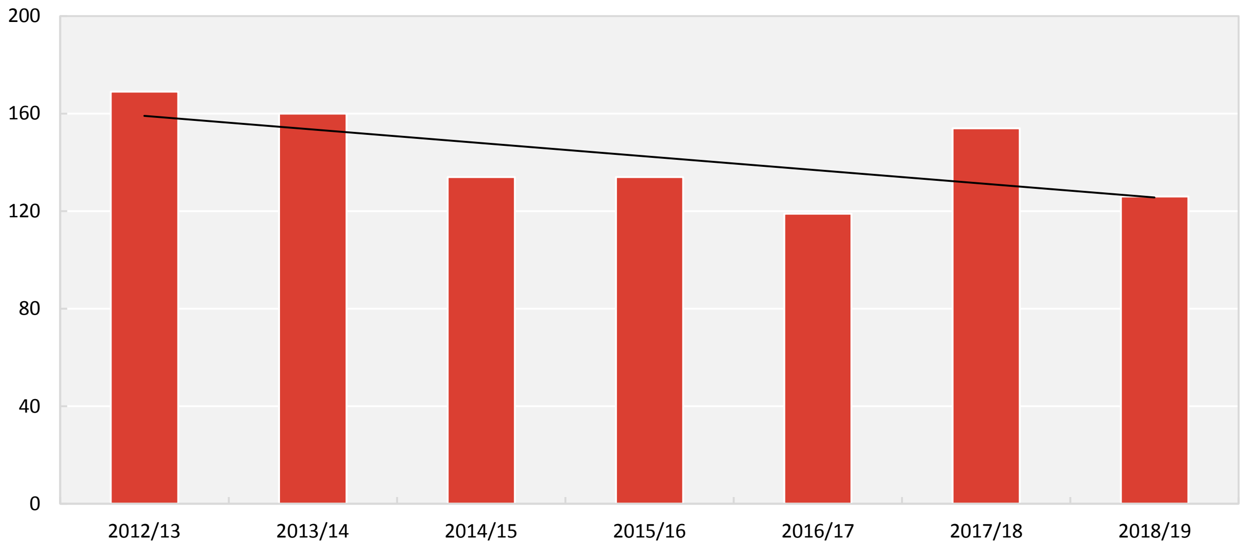
We support the AER's draft customer service incentive scheme which enables distributors to propose a new incentive around customer service under the small scale incentive scheme framework. In accordance with the AER's draft scheme, we intend to continue working with our customers to develop an incentive scheme which targets services they value. We intend to submit the details of this scheme with our revised regulatory proposal.

F-factor scheme

The F-factor scheme provides incentives for us to reduce the risk of fire starts from our assets. Figure 10.1 demonstrates historical fire starts on our network.

178 PAL MOD 10.12: Powercor, *Targets*, January 2020. PAL MOD 10.11: Powercor, *Incentives* January 2020.

Figure 10.1 Number of fire starts



Source: Powercor

We propose to continue to apply the F-factor scheme during the 2021–2026 regulatory period, consistent with the AER's framework and approach paper.

The Victorian government is presently reviewing the approach for setting the F-factor scheme targets and is expected to publish a revised F-factor Order in Council in 2020. Once published, we propose applying the revised F-factor order and subsequent revised AER's F-factor scheme determination.

10.2.10 Control mechanisms

The control mechanism imposes limits on the prices that we can charge. More information on this is available in our control mechanism appendix.[179]

179 PAL APP08: Powercor, *Price control formula*, January 2020.

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11 Metering

Summary

The introduction of smart meters in Victoria is a success story. We delivered an efficient roll out of the advanced metering infrastructure, including the meters, the communications network and IT infrastructure, on time and on budget. We have the lowest metering charges in Victoria.

Our smart meters are a rich source of data that we use to deliver better services to our customers, and manage the network more efficiently. We have embedded the use of smart meter data and services in our daily operations and have revolutionised network operations. This has resulted in improved network reliability and safety, and reduced network operating costs, delivering major benefits for customers.

Our customers will continue to benefit from us providing metering services in the 2021–2026 regulatory period. We will reduce our average metering charges by 13%.

As we lower charges we will ensure customers continue to receive existing smart meter benefits as well as additional services.

11.1 What we plan to deliver

We provide an efficient metering service to our residential and small business customers. The service involves installing and maintaining smart meters for customers who consume less than 160MWh, and remotely collecting and processing energy data from these meters. It also includes the maintenance and reads of the remaining fleet of manually-read meters.

Victoria has been a pioneer in the NEM for adopting smart meter technology. In 2009, the Victorian Government required distributors to roll-out smart meters for all residential and small business customers. This reflected the significant benefits for customers from smart meters, including the synergies from a mass roll-out.

We currently have more than 879,000 smart meters across our network, covering 97.7% of our residential customers. We also have a web of communication devices that allow us to remotely operate and collect data from the meters. Our IT systems allow us to process and validate smart meter data.

11.1.1 Customers benefit from smart meters

Customers have benefited, and continue to benefit, from our smart meter infrastructure. Key benefits are outlined in figure 11.1.

Figure 11.1 Benefits to customers from smart meters across the lifecycle of our services

CONNECT

Timely connection

Ongoing savings from remote meter read
Customers no longer have to pay for site visits for meter reads and tests

Streamlining connections
Connect customers and install meters in a single appointment, rather than multiple visits

Reconnecting remotely
Remotely reconnect a customer without having to visit the customer's site

Connecting solar
Remotely reconfigure smart meters for solar exports

SUPPLY

Better electricity supply

Improving safety at customers premise
Remotely identify neutral integrity issues in a customer's home that may have led to electric shocks

Integrating solar and batteries
Help us understand when it is safe to export electricity into the network

Improving security
Reduce load by managing voltage at times of peak demand, avoiding potential blackouts

RESTORE

Fix outages quicker

Shorter outages
Detect outages quicker, so we can get power back on for our customers in a shorter time

Rotating load in emergencies
Share and rotate energy among our customers in times of emergency. We can prioritise life-support customers and critical infrastructure in these cases

Identifying faults at home
Provide information on whether an outage is caused by the network or a customer's home

BILLING

Efficient billing

Real time usage
Provide next-day insights into usage patterns to help customers manage their bills and compare tariff options

Improved data accuracy
Provide more than 99% accurate data each day, minimising data errors

Notification if a meter fails
Customers are at less risk of a incorrect bill from a faulty meter, as we receive a signal when a meter has failed

EFFICIENCY

Lower long-term costs

Reducing peak demand
Control and distribute load among customers efficiently to reduce peak demand and need for augmentation

Improving power quality
Monitor voltage and reduce any potential issues before they occur

Improved visibility
Visibility of much if the low voltage network, including load data

Source: Powercor

The smart meters in Victoria and other states differ markedly. While all customers with smart meters benefit from the savings of moving from manually to remotely read meters, Victorian customers also benefit from the rich source of power quality data for network management and optimisation. Only Victorian smart meters are required to be installed with functionality that enables this data to be collected.

Victorian smart meter functionality is essential to meeting our technology vision for our network, including providing full visibility of the LV network as outlined in our digital networks proposal, and managing the increasing penetration of rooftop solar (and other technologies) that will lead to more exports on the network and the need to manage two-way flow and voltage variations.

Therefore, the continuation and realisation of the full range of smart meter customer benefits is highly dependent on key functions that are required under the Victorian functional specification. Some of the new benefits that will continue to be generated by smart meters are discussed below.

We will make it easier for customers to use their smart meter data

We will streamline customers' access to smart mater data during the 2021–2026 regulatory period. As detailed in our ICT chapter, we will introduce a new one-stop-shop portal and mobile application where customers can easily access their usage data in 15-minute snapshots. This will help them better understand their usage patterns and track the usage of individual appliances by isolating appliances through usage patterns.

We will explore innovative ways to present this data, including measuring the efficiency of customers' exports. This will empower customers to make informed choices on energy use, explore the benefits of participating in demand management and energy markets, and choose suitable tariff offerings.

Stakeholder feedback

Throughout our research, our customers have told us they are interested in accessing more data on their energy use, using the data to make more informed choices and participate in demand response programs. Most engaged customers expressed interest in taking steps to manage their own demand through use of real or near real-time data:

> 'I *would be very interested in using my data. I want to know what I am using, how I am being charged… What difference it makes if I don't have my TV on for a week.'*
>
> *'Only if [data] it's easy to use… it needs to be effective!'*

The smart meters are a rich source of data that our customers can use to shape their energy use. As owners and operators of the smart meter infrastructure, we will continue to empower customers by improving meter data accessibility.

We will use smart meter data to assist the DER register

To better understand the level of penetration of DER across Australia, AEMO will manage a DER register from December 2019 with assistance from distributors. As the penetration of solar rooftop and batteries grows, we will use the smart meter export data to locate premises with exports, to assist AEMO in maintaining the register.

Expanding our analytical capabilities

We are only at the beginning of our journey in uncovering the analytical possibilities of the rich power quality data provided by smart meters. We expect that complimentary investments in our digital networks initiative will allow us to leverage the data in smart meters to drive further innovation in our business.

11.1.2 We will reduce our meter charge in 2021–2026

Our customers will continue to benefit from us providing metering services in the 2021–2026 regulatory period, as we will reduce our average metering charge by 13%. We operate an efficient business that continually looks for ways to keep the price as low as possible. Our customers are now sharing the benefits associated with the mass rollout.

Table 11.1 summarises our annual metering charges from 2020 to 2025/2026.

Table 11.1 Metering charges from 2020 to 2025/2026 ($, 2021)

Meter type	2020	2021/22	2022/23	2023/24	2024/25	2025/26
Single phase	68.1	59.2	57.9	56.7	55.6	54.5
Three phase direct connected meter	75.0	65.2	63.8	62.5	61.2	60.0
Three phase CT connected meter	125.4	108.9	106.6	104.4	102.3	100.3

Source: Powercor

A key advantage of a network providing a metering service is our natural economies of scale, efficiencies from bulk purchases and storage, and synergies from operating the necessary communication infrastructure. It also means that customers have a single point of contact, as the same crew can handle connections, faults and meter installations in one visit to achieve much lower meter installation timeframes.

As we lower charges, we will ensure customers continue to receive existing smart meter benefits and additional services. More customers will also have smart meters, as we continue to replace legacy manually-read meters on the network.

11.2 Our forecasting approach

Our proposed meter charges for the 2021–2026 regulatory period seek to recover the efficient costs of providing the metering service. Similar to standard control services, we use a post-tax revenue model (**PTRM**) to calculate revenue based on key inputs such as the metering RAB, new capital expenditure, rate of return, operating expenditure and tax. We then determine a charge for an individual type of meter.

In the sections below we identify our method and key inputs to forecast metering charges.

11.2.1 Our forecast meter volumes reflect the experience on our network

The majority of our forecast metering investment in the 2021–2026 regulatory period will be procuring and installing smart meters. We forecast volumes of new and upgraded customer connections, together with volumes of replacement for faulty smart meters and older accumulation meters as follows:

- new customer connections are based on economic advice provided by the Centre for International Economics and volumes of smart meters for customer requested additions and alterations based on historical trends.
- volumes of meter replacement due to network faults are based on historical fault rates (we reactively replace meters when they fail due to a network fault).
- volumes of replacement due to meter faults are based on meter type, estimated asset life and condition. We proactively replace meters when we recognise a systematic failure mode impacting a specific type of smart meter or a family of meters.
- replacement volumes for accumulation meters—at the time of our roll-out there were a small number of premises that either opted out of installing smart meters or were inaccessible. Over time, we have been replacing these meters as customers request a smart meter, or where the accumulation meter has failed. Our forecast approach is based on volumes of accumulation meters and experience with previous roll-outs.

Table 11.2 sets out the volumes of smart meters we expect to procure and install on the network in 2021–2026. More information is available in the metering cost model.[180]

[180] PAL MOD 11.04 - Metering cost model - Jan2020 - Public.

Table 11.2 Forecast volumes of smart meter installations in the 2021–2026 regulatory period

Driver	Volumes
New connections	136,581
Supply upgrades (additions and alterations)	5,304
Replacements due to network fault	3,949
Meter fault replacement	54,284
Accumulation meter replacement	11,026
Total smart meters	**211,144**

Source: Powercor

11.2.2 Our costs are market tested

We procure smart meter and communication devices from competitive service providers. This provides confidence that the cost of undertaking the capital works are efficient and market tested.

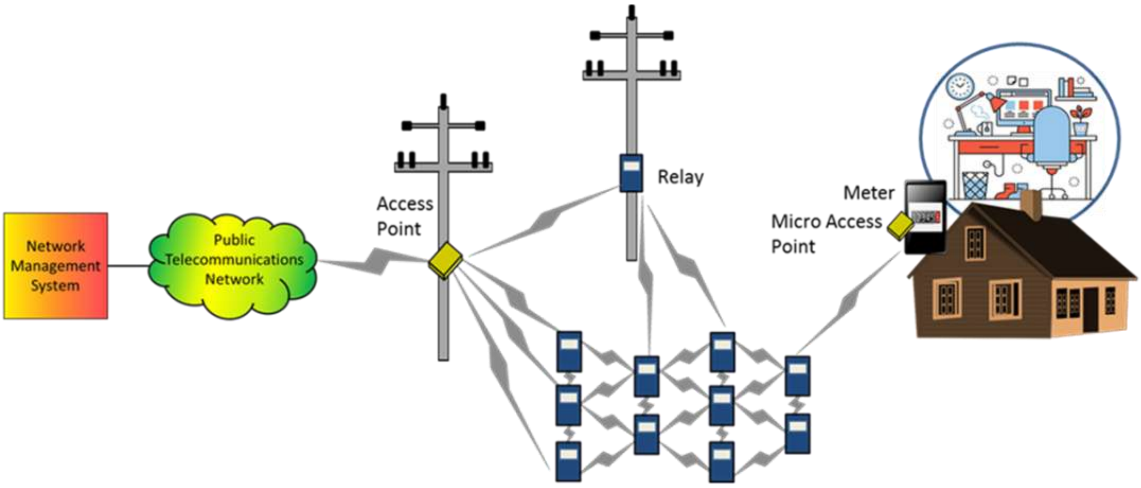
In our forecast, we have used:

- unit rates to procure smart meters and communication devices based on current prices of our suppliers. The unit rates reflect the market-tested cost of hardware.
- for installation costs, we have used labour hours and rates based on current contracts with suppliers. We have sufficient data to identify the forecast hours and complexity for undertaking different jobs (e.g. meter fault replacement has a lower labour cost than replacement caused by network fault, due to the ability to plan ahead).

11.2.3 All customers benefit from our smart meter communications network

Our smart meter communications network comprises a series of communications devices—mainly access points and relays—and a network management system that communicates through the public telecommunications network as depicted in figure 11.2. Other smaller devices that are part of the communications network comprise modems, antennas and batteries.

Figure 11.2 Communication devices



Source: Powercor

The communications network transmits smart meter data at various intervals, depending on the use of that data. Currently we collect data at the following intervals:

- usage data every 30-minutes
- power quality data every 15 minutes
- additional power quality data from various sites for advanced data analytics every 5 minutes.

In 2018, power quality data accounted for 88% of all data collected and transmitted through the smart meter communications network. We expect this share to remain relatively constant by 2025/26.

Given the smart meter communications network mainly transmits data used for network management and optimisation, the benefits of the communications network investment is largely shared by all our customers. As we continue to develop our smart meter data analytics to develop innovative ways to optimise the network and defer network augmentation, all our customers will continue to benefit from the smart meter communications network, including those with contestable meters.

For the 2021–2026 regulatory period, therefore, we have allocated future capital investment for communications device replacements, and operating expenditure related to maintaining the communications network, as follows:

- 88% to standard control services
- 12% to metering services.

Our forecast of the total capital volumes for communications devices is based on historical fault rates, and new growth based on customer numbers, which are outlined in the communications model.[181]

11.2.4 We use the base-step-trend approach to forecast operating expenditure

We incur operating expenditure to collect and verify metering data, to maintain and test meters, to provide customer services, and to operate our communication devices.

181 PAL MOD 6.03 - AMI comms - Jan2020 - Public.

We use the AER preferred base-step-trend approach to forecast metering operating expenditure whereby we:

- nominate 2019 as our efficient revealed base year
- adjust our base to remove operating expenditure related to the maintenance of the smart meter communications network
- add to the base year the efficient level of operating expenditure determined by applying a rate of change that comprises labour price escalation and an increase in scale
- add a negative step change to reflect the reduction in the cost of manual meter reads resulting from the expected replacement of legacy meters.

This is outlined in more detail in our metering models.[182]

11.2.5 Our revenue forecast is based on the PTRM model

We have used the AER's PTRM model to calculate the forecast revenue necessary for the efficient provision of metering services during the 2021–2026 regulatory period. Table 11.3 shows these building blocks.

Table 11.3 Building blocks of revenue requirement for metering services for 2021–2026 ($ million, nominal)

Revenue requirement building blocks	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Return on capital	10.4	9.8	9.0	8.2	7.4	44.8
Regulatory depreciation	26.8	29.1	31.5	33.9	35.8	157.0
Operating expenditure	11.2	12.0	12.7	13.5	14.2	63.6
Net tax allowance	2.9	2.7	3.0	3.1	3.1	14.8
Unsmoothed revenue requirement	51.4	53.5	56.2	58.6	60.5	280.2
Smoothed metering revenue	**53.3**	**54.6**	**55.9**	**57.3**	**58.6**	**279.8**

Source: Powercor

182 PAL MOD 11.03 - Metering 2015 closing RAB - Jan2020 - Public; PAL MOD 11.02 - Metering PTRM & exit fees 2021-26 - Jan2020 - Public; PAL MOD 11.05 - Metering RFM 2016-20 - Jan2020 - Public.

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12 Alternative control services

Summary

Alternative control services (**ACS**) are our customer requested services that are directly recovered from customers seeking the service. They include network ancillary services, such as customer connections, as well as public lighting services. Metering provision services are covered separately.

Our ACS proposal for the 2021–2026 regulatory period incorporates service classifications made in the AER's framework and approach paper. This includes the reclassification of some service trucks to standard control services, introduction of new services previously labelled as service trucks, and the reclassification of previously negotiated services. We will also be abolishing remote re-energisation and de-energisation, providing these services to our customers with smart meters without charge.

We have heard our customers' top concern is affordability and so we are proposing to keep our prices constant in real terms.

With more quoted services from 2021, we are proposing three new labour types for quoted labour rates—increasing quoted labour types from two to five. Our labour rates are based on our efficient 2019 actual rates, inclusive of overheads, escalated by our independently sourced labour price growth forecasts.

Our proposal for public lighting services for the 2021–2026 regulatory period reflects customer preferences for a rapid move to more efficient light alternatives, as well as the need to improve the accuracy of cost allocation across different light types.

12.1 What we plan to deliver

In the following sections we discuss our network ancillary services and public lighting services.

12.1.1 Network ancillary services

Network ancillary services are non-routine services provided to customers on an 'as needs basis'. Depending on the service, the charge we apply may be a fixed (fee based) charge or variable (quoted) charge based on time and materials to complete the activity.

Fee based services

Fee based services are activities which are fixed in nature and are charged on a per activity basis. For the 2021–2026 regulatory period, we will make changes to our fee based services consistent with the AER's framework and approach paper.

We have abolished the service truck visit charge because the framework and approach paper outlines that this is not a distribution service, but rather an input in delivering a distribution service. As such, the service truck visit charge requires reclassifying.

There is a wide variety of services that fall under the service truck visit task that applies in the 2016–2020 regulatory period and which must now be reclassified. To ensure cost-reflectivity and simplicity, we have adopted an approach of classifying the service according to the length of the task:

- isolation of supply or reconnection, excluding HV (usually less than 30 minutes)
- standard alteration (usually between 30 and 60 minutes)
- complex alteration (usually longer than 60 minutes).

We have also created a single charge for short jobs commonly carried out on the same day. For example, a customer may request an isolation and a reconnection within a short space of time. Rather than levying two short services, we will introduce a single charge that includes two visits in the same day and is around 10% lower than the combined two short charges together.

For the 2021–2026 regulatory period, the 'wasted service truck visits' will be reclassified as standard control according to the framework and approach paper. As such, we have created a new charge 'failed field visit' for circumstances when the crew are sent to conduct works that are classified as ACS but are unable to carry out their works due to conditions within the customers' control.

Our customers are already benefiting from smart meters by having access to remote services without the need for site visits, including remote meter reads, remote re-energisation and remote de-energisation. As owners and operators of smart meters, we have the economies of scale to offer these services affordably and at almost no cost. For the 2021–2026 regulatory period, we will continue to provide benefits to our smart meter customers by abolishing remote re-energisation and remote de-energisation fees—providing these services to our customers free of charge. We already provide a number of services free of charge to our customers, including:

- abolishments under 100 amps (or non-complex)
- desktop and site assessments for No Go Zones.

We are also abolishing a fixed-fee charge for access to meter data and propose to create a quoted charge for meter and network data access for cumbersome requests only.

The abolished charges for the 2021–2026 regulatory period are outlined in table 12.1.

Table 12.1 Abolished charges for the 2021–2026 regulatory period

Service group	Description
Service truck visits	To align with the framework and approach paper
Remote re-energisations / de-energisations	Immaterial costs and so these services will be offered free of charge
Access to meter data	This charge will become a quoted service charge

Source: Powercor

Our proposed fee based services over the 2021–2026 regulatory period are outlined in table 12.2. Our charges are available in our ACS appendix and more detail is provided in our model.[183]

183 PAL APP09: Powercor, *ACS charges,* January 2020; PAL MOD 12.01 - Fee based - Jan2020 - Public.

Table 12.2 Description of fee based services for the 2021–2026 regulatory period

Service group	Fee based service	Description
Existing charges that will remain		
	Basic connections (BH/AH)	This charge applies for retail customers seeking a basic connection service or proposes to become a micro-embedded generator.
	Meter/NMI/site investigation	This charge applies when a request is received to investigate the metering/connection at a given supply point. This request may be initiated by either the retailer or a customer.
	Remote meter re-configuration	This charge applies when a request is received to reconfigure a smart meter and has the related infrastructure in place.
	Field-based special read	This charge applies when a request is received to manually read a meter outside of the cycle.
	Meter testing	This charge applies when a request is made to test the accuracy of a meter (or meters) at a given supply point.
	Manual re-energisation	This charge applies when a request is received to re-energise a supply point for fuses less than 100 amps by a field visit. The two options for re-energisations available: • reconnections (same day) business hours only • reconnections (including customer transfers) business hours
	Manual de-energisation	This charge applies when a request is received to de-energise (including disconnections for non-payment) a supply for fuses less than 100 amps by a field visit.
New charges		
	Isolation of supply or reconnection, excluding HV (single) (BH/AH)	This charge applies when a customer requests an isolation of supply (e.g. to allow customer and/or contractor to perform maintenance on the customer's assets, work close to or for safe approach), or a reconnection of supply after the isolation, excluding high-voltage (**HV**) assets. It also includes requests for disconnection at the point of supply (i.e. pole or pit) and also includes service line isolations in association with No Go Zone applications.
	Isolation of supply and reconnection after isolation, excluding HV (same day) (BH)	This charge applies when a customer requests both an isolation of supply and a reconnection of the same point of supply on the same day during business hours, excluding HV assets.
	Standard alteration, 30-60 minutes (BH/AH)	This charge is for alteration services expected to last 30 to 60 minutes, including but not limited to the following services: • install or remove controlled load • move meter to new position • relocate point of attachment or service • replace meter panel • re-route mains to new pit • upgrade maximum demand or change supply capacity control • replacing fascia board. If multiple of the above services are required for the customer's alteration, this may be deemed a complex alteration.

Complex alteration, > 60 minutes (BH/AH)	This charge is for alteration services expected to be more than 60 minutes, including but not limited to the following services: • change overhead to underground • change to group metering panel • upgrade phase. It also includes multiple services during the same site visit, for example a customer requests a metering panel replacement and moving a meter to a new position in the same visit.
Failed field visit (unable to perform customer requested task) (BH/AH)	This charge applies when a fixed-fee ancillary service is requested by the customer or a third party but the field crew cannot perform the task once arriving at the site due to customer fault. For example, the site is locked with a non-industry lock preventing access for our crews. Other examples are available in our attached pricing proposal.[184]

Source: Powercor
Notes: BH refers to business hours and AH refers to after hours

Quoted services

Quoted services are variable in nature and levied on a time and materials basis. Table 12.4 presents a description of our quoted services for the 2021–2026 regulatory period. The quoted services have been updated to reflect new classifications in the AER's framework and approach paper. Our pricing formula for quoted services and our quoted labour rates are attached.[185]

[184] PAL ATT142: Powercor, *Pricing proposal 2020*, November 2019.

[185] PAL APP08: Powercor, *Price control formula*, January 2020. PAL APP09: Powercor, *ACS charges,* January 2020.

Table 12.3 Proposed quoted services for the 2021–2026 regulatory period

Quoted services	Description
Complex supply abolishment	This charge applies when a customer requests permanent removal of our supply assets on a complex site. For example, when supply is directly from a sub-station, when the abolishment requires a design to be completed safely, or when the supply is more than 100 amps.
Rearrangement of network assets at customer request, excluding public lighting assets	This charge applies when a customer requests capital work for which the prime purpose is to satisfy a customer requirement other than new or increased supply, other than where Guideline 14 applies. For example, a customer requests a removal or relocation of service to allow work on private installation.
Audit design and construction	This charge applies when either a third party requests or we deem it necessary to review, approve or accept work undertaken by a third party. Examples include: • customer provided buildings, conduits or ducts used to house our electrical assets • customer provided connection facilities including switchboards used in the connection of an electricity supply to their installation • any electrical distribution work completed by our approved contractor that has been engaged by a customer • provision of system plans and system planning scopes, for designers engaged by the customer • reviewing and/or approving plans submitted by designers engaged by the customer.
Specification and design enquiry	This charge applies when design or network planning is required to fairly assess the costs so that an offer can be issued to a customer. Examples include: • the route of the network extension required to reach the customer's property • the location of other utility assets • environmental considerations including tree clearing • obtaining necessary permits from State and Local Government bodies • assessment of design and network planning options • specialist services (which may involve design related activities and oversight/inspection works) where the design or construction in is non-standard, technically complex or environmentally sensitive and any enquiries related to distributor assets.
Elective undergrounding	This charge applies when a customer could receive an overhead service but requests an underground service, other than where Guideline 14 applies. For example, a customer requests an underground service where we would consider it safe and prudent to install an overhead service.
High load escorts–surveying and lifting overhead lines	This charge applies when a third party requires safe clearance of overhead lines to allow high load vehicles to pass along roads. This includes surveying and lifting of overhead lines.
High profile antenna installation	This charge applies when customers request to install a high profile antenna to an existing smart meter.
No-go zone safety-related services	This charge applies when a customer or third party requests services related to ensuring safety of no-go zone around our assets, including a supply isolation, covering assets with tiger tails and aerial markers, and other related works. For example, a customer/third party is conducting building works at a site near our assets where visual markers (tiger tails) are required for safety.
Reserve feeder maintenance	This charge applies when a customer requests continuity of electricity supply should the feeder providing normal supply to their connection experience interruption. The fee covers the maintenance of the service, it does not include the capital required to implement or replace the service as this is a negotiated connection service.

Alteration and relocation of public lighting assets	This charge applies when a customer or a third party requests alteration, rearrangement or relocation of public lighting assets.
New public lighting services including greenfield sites and new light types	This charge applies when a customer or a third party request an installation of new public lighting assets, including new light types and emerging light technologies.
Access to network data	This charge applies when a customer or a third party requests electricity network data, including aggregates smart meter data, outside of legislative obligations. For example, a third party requests large quantities of aggregated data outside of our standard practices of legislative obligations.
Complex isolations and alterations, including HV	This charge applies when a customer requests an isolation of supply (e.g. to allow customer and/or contractor to perform maintenance on the customer's assets, work close to or for safe approach) of HV assets or where there are more complex/larger scale works isolation or alternations. This also includes where works are requested to be perform after hours for multi-occupancy or complex sites. For example, after-hours isolation for customer side works at a large multi-occupancy site, such as a caravan park.
Alterations to the shared distribution network assets	This charge applies when a customer or third party initiates alterations or other improvements to the shared distribution network to enable the third party infrastructure (e.g. NBN Co telecommunications assets) to be installed/altered on the shared distribution network.

Source: Powercor

We are proposing five regulated labour types for quoted services to reflect the varying type of labour requirements across quoted service jobs. Table 12.4 summarises our proposed labour type for quoted service for the 2021–2026 regulatory period. Our rates are available in the ACS appendix and more detail is provided in our model.[186]

Table 12.4 Description of quoted labour type and rates for the 2021–2026 regulatory period

Labour type	Description
Administration	Business support officers, project creation and close-out, project administration
Field worker	Trade skilled worker, asset locators, customer connection officers, compliance officers, substation construction, maintenance, testing
Technical	Metering services, SCADA, telecommunication officers, network facilities, quality of supply officers, telecommunications network operating, network standards, network access, substation estimators, surveyors
Engineer	Designers, project engineers
Senior engineer	Senior and principal engineers, senior designers, network planning, network protection

Source: Powercor

186 PAL APP09: Powercor, *ACS charges,* January 2020; PAL MOD 12.02 - Quoted services labour rate - Jan2020 - Public.

12.1.2 Public lighting

We provide public lighting services for local councils and Victorian Department of Transport. The provision of public lighting services and the respective obligations of our business and public lighting customers are regulated by the Victorian Public Lighting Code.[187]

Table 12.5 summarises the changes to the treatment of public lighting services for the 2016–2020 regulatory period as per AER's framework and approach paper. Our public lighting charges are available in the ACS appendix and more detail is provided in our model.[188]

Table 12.5 Changes in classification of public lighting services

Service group	2016–2020	2021–2026
Operation, maintenance, repair and replacement of public lighting assets	Alternative control service, fee based	Alternative control service, fee based
Alteration and relocation of public lighting assets	Negotiated	Alternative control service, quoted
Provision of new public lighting	Negotiated	Alternative control service, quoted

Source: Powercor

Operation, maintenance, repair and replacement of public lighting

We own and maintain more than 178,000 public lighting across our network. This includes ensuring the lights are operational and safe, periodically replacing lamps and repairing or replacing any luminaires, poles and brackets before or after they fail. The local councils and the Department of Transport pay a fixed annual fee per light—the operation, maintenance, repair and replacement (**OM&R**) charge.

We have around 30 types of approved lights on our network, including minor and major road lights, with more councils opting for efficient light alternatives. In 2019, around 57% of all public lights on our network were efficient alternatives, with more than 71% of these in minor roads. Table 12.6 summarises the existing stock of public lights on our network per reference light type (each reference light type has multiple light types within it).

187 PAL ATT005: Essential Services Commission of Victoria, *Public lighting code*, December 2015.

188 PAL APP09: Powercor, *ACS charges,* January 2020; PAL MOD 13.01 - Public lighting - Jan2020 - Public.

Table 12.6 Current public lighting stock we manage per reference light type (2019)

Light category	Description	Number
MV80	Minor road lights with gas discharge lamps that use an electric arc through vaporised mercury to produce light. These are the least efficient public lights	36,714
High pressure sodium (**SHP**) 150W	Major road high pressures lights with gas discharge lamps. These are the least efficient major road lights	26,323
SHP250W	Major road high pressures lights with gas discharge lamps	14,495
Fluorescent lamps T5	Minor road lights with MV gas discharge lamps that are more efficient than MV80s as they use fluorescence to produce visible light	12,801
Compact fluorescent	Minor road lights that are more efficient than MV80s by running electricity through gas inside the coils, exciting that gas, and producing light	9,909
Light emitting diode (**LED**) Category P	Efficient minor road lights with LED lamps with a longer lifespan than most lights are more efficient than fluorescent lights	70,570
LED Category V	Efficient major road lights with LED lamps.	7,987
Total		**178,799**

Source: Powercor

Together with our customers, we are committed to replacing inefficient lights with more efficient alternatives as quickly as possible. Efficient light alternatives result in lower electricity bills and present an opportunity to install smart controls that will in the future enable further savings and control of lights in the future.

The majority of our minor road lights have been replaced by efficient light alternatives in bulk council replacements. Major road lights however remain mostly inefficient. Over time, it will become more difficult and potentially costly to source inefficient lights and there will be declining community support.

We have already changed our practices to reflect the declining market for inefficient lights. If a luminaire fails today, we will only replace it with the most efficient LED alternative. That means failing MV80s or T5s will only be replaced with Cat P LEDs and failing SHPs will be replaced with Cat V LEDs. We propose to continue this approach during the 2021–2026 regulatory period to help our customers reach their efficiency goals sooner. The only exception is the replacement of decorative lights where the councils choose what luminaire we install.[189]

To minimise costs to all customers, we only replace those lights if they fail or if the replacement is necessary. Our customers will make the decision if they wish to replace the remaining inefficient lights in bulk.

In the future, if Australia ratifies the United Nations Minamata Convention on Mercury, the importation of mercury vapour lamps will be banned after 2020. This will require a change in processes where we either use a LED lamp in inefficient luminaires or we replace the luminaires.

189 Installation of new or repaired decorative lights must comply with current standards which prohibit the use of mercury vapour lanterns.

Stakeholder feedback

In September 2019, we held an Open House engagement with our councils, Members of Parliament, Green House Alliances, the Public Lighting Group, Municipal of Victoria and Community Energy groups, where we presented our public lighting proposals. The forum participants strongly supported a complete phase-out of inefficient lights and a change in practice where all failed lights are replaced by the efficient LED alternatives. Customers also supported replacement of lamps in decorative lights with efficient photo-electric cells.

For more details on outcomes of the Open House engagement refer to our stakeholder engagement attachment.[190]

12.2 Our forecasting approach

12.2.1 Network ancillary fee-based services

Our proposed methodology for revising our ACS fixed charges for the 2021–2026 regulatory period has been to escalate each of our existing charges by labour escalation and CPI. For new fee-based services, we used a revenue-neutral volume weighted approach to develop the charges for each of the newly created services. This method has been chosen to align the approaches between existing and new charges.

12.2.2 Public lighting fee-based services

We use the AER's public lighting model to forecast the OM&R charge for each light type across our network. We have updated the following key assumptions in the model:

- labour escalation for 2021–2026
- fault and failure rates for each light type, measured as an average of actual fault and failure rates during 2016–2018 where available
- the cost of replacing a pole, to better reflect the actual cost incurred.

We have also made a structural change to the model, based on a change in internal asset management practices and international best-practices:

- we have introduced a new light type, major road category V LED light
- we have assumed that by 1 July 2021, we will no longer be replacing inefficient light luminaires like-for-like. Rather, all fault or failure replacements will be with efficient LED alternatives (category P LED for minor roads and category V LED for major roads). This excludes decorative light luminaires which require non-standard fittings
- for decorative lights we have assumed lamp replacements will be with efficient LED alternatives
- we have smoothed the charges to be constant over the regulatory period.

190 PAL ATT071: Powercor, *Open house findings report*, October 2019.

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13 Managing uncertainty

Summary

We operate in an uncertain environment in which uncontrollable external events can alter the quantity and nature of services required to be provided to our customers. While our forecasts have been prepared based on the best information currently available for what we will need to do during the 2021–2026 regulatory period, we are unable to predict each and every event that will occur.

This chapter sets out our proposed nominated pass-through events for the 2021–2026 regulatory period.

The uncertainty regime under the Rules comprises pass-through events, capital expenditure reopeners and contingent projects. These mechanisms deal with expenditure that may be required during a regulatory period but which are not able to be predicted with reasonable certainty at the time of preparing or submitting a regulatory proposal to the AER.

Rather than building up our expenditure forecasts to cover every possible eventuality, we propose nominated pass-through events in this regulatory proposal so as to enable us to request extra funding from the AER during the regulatory period if a large unexpected event occurs, or where we are unable to cost an anticipated event given limitations on the works we may be required to undertake. The exclusion of the costs of these uncertain events from our regulatory proposal ensures our customers face the lowest possible prices.

13.1 Pass-through events

The pass-through mechanism in the Rules recognises that a distributor can be exposed to risks beyond its control, which may have a material impact on its costs. A cost pass-through enables a distributor to recover the costs of defined unpredictable, high-cost events not built into the AER's distribution determination.

In addition to the pass-through events specified in the Rules, an event may be defined by the AER in a distribution determination. We propose the following nominated pass-through events be accepted by the AER in our distribution determination.

Table 13.1 Proposed nominated pass-through events

Type of event	Changes from current definition / definition in recent regulatory decisions
Insurer credit risk event	Consistent with current definition and definition accepted by AER in recent regulatory decisions
Insurance coverage event	Amendment from the current 'insurance cap event' having regard to the changes and challenges in the global insurance market that have increased the risk of inability to obtain the full level or scope of cover under relevant insurance policy or policies
Natural disaster event	Minor amendment to current definition and consistent with recent AER regulatory decisions
A terrorism event	Current definition amended to include specific reference to cyber terrorism
Retailer insolvency event	Minor amendment from current definition having regard to the current definition of the retailer insolvency event in the Rules
Major cyber event	Additional event with definition that addresses AER reservations expressed in recent decisions
Act of aggression event	Additional event added with definition that addresses AER reservations with this event expressed in recent regulatory decisions
Electric vehicle event	Additional event added to address the uncertainty with electric vehicle uptake

Source: Powercor

Each of these proposed nominated pass-through events is consistent with the nominated pass-through event considerations. In particular, each event:

- can be clearly identified and defined; is not covered by the pass-through events specified by the Rules
- has a low probability of occurrence but the potential to have a significant cost impact
- is beyond a distributor's ability to prevent, substantially mitigate, commercially insure or self-insure acting prudently and efficiently
- identifies any additional factors that it is known will be relevant in assessing the amount to be passed through for the purpose of a pass-through application for the event.[191]

Further, with the exception only of the major cyber event, the act of aggression and the electric vehicle event, each of the proposed nominated pass-through events is consistent with the nominated pass-through events accepted by the AER in its recent decisions for other service providers.

Further information on our nominated pass-through events is set out in our attached managing uncertainty appendix.

13.2 Application of cost pass-throughs to alternative control services

We also propose the AER apply the pass-through provisions for the Rules' specified and nominated pass-through events to alternative control services. We propose applying a modified materiality threshold and that an approved pass-through amount (or part thereof) that relates to the increased costs of providing alternative control services be recovered through alternative control services pricing, rather than standard control services charges.[192]

[191] NER, clause 6.6.1(j).

[192] PAL APP04: Powercor, *Uncertainty appendix*, January 2020.

A Glossary

Term	Definition
2018 RORI	2018 Rate of Return Instrument
ABS	Australian Bureau of Statistics
ACIF	Australian Construction Industry Forum
ACMA	Australian Communications and Media Authority
ACR	Automatic circuit recloser
ACS	Alternative control services
AEF	Australian Energy Foundation
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFAP	As far as practicable
Amended Bushfire Mitigation Regulations	Electricity Safety (Bushfire Mitigation) Amendment Regulations 2016
AREMI	Australian Renewable Energy Mapping Infrastructure
BI/BW	Business intelligence and business warehousing
BIS Oxford	BIS Oxford Economics
BMP	Bushfire Mitigation Plan
Bpaa	Basis points per annum
CBRM	Condition based risk management
CCC	Customer Consultative Committee
CCP	Consumer Challenge Panel
CCTV	Closed-circuit television
CESS	Capital Expenditure Sharing Scheme
CFA	Country Fire Authority
CIE	Centre for International Economics
CPI	Consumer Price Index

CRO	Caution refer operations
CT meters	Meters with current transformers
DAPR	Distribution Annual Planning Report
DEDJTR	Department of Economic Development, Jobs , Transport and Resources
DELWP	Department of Environment, Land, Water and Planning
DER	Distributed energy resources
DMIA	Demand Management Innovation Allowance
DMIS	Demand Management Incentive Scheme
Draft regulations	Environment Protection Regulations
DUoS	Distribution Use of System
EBSS	Efficiency Benefit Sharing Scheme
EDO	Expulsion dropout
EFCAP	Energy Futures Customer Advisory Panel
EGWWS	Electricity Gas Water and Waste Services
ELCA	Electric line clearance area
EPA	Environment Protection Authority Victoria
EP Act 1970	Environment Protection Act 1970
EP Amendment Act 2018	Environment Protection Amendment Act 2018
ESCV	Essential Services Commission of Victoria
ESV	Energy Safe Victoria
EV	Electric vehicle
FG	Felten and Guilleaume
FOLCB	Fused overhead line connector box
Frontier	Frontier Economics
GFN	Ground fault neutraliser
GSL	Guaranteed service level

GST	Goods and services tax
Guideline 14	Electricity Industry Guideline No 14 – Provision of Services by Electricity Distributors
HBRA	High bushfire risk areas
HSE	Health, safety and environment
HV	High voltage
IAP2	International Association for Public Participation
ICT	Information and communications technology
IT	Information technology
kV	Kilovolt
kVA	Kilovolt ampere
kWh	Kilowatt hour
LBRA	Low bushfire risk areas
LiDAR	Light detection and ranging
LPG	Liquefied petroleum gas
LS	Least Squares
LSAA	Local service are agents
LV	Low-voltage
MAIFI(e)	Momentary average interruption frequency index (event)
MCR	Marginal cost of reinforcement
MED	Major event day
MVA	Megavolt ampere
MW	Megawatts
MWh	Megawatt hour
NEL	National Electricity Law
NEM	National Electricity Market
NERA	NERA Economic Consulting

NPV	Net present value
NST	Neutral screen testing
OM&R	Operation, maintenance, repair and replacement
PRF	Powerline replacement fund
PTRM	Post tax revenue model
PV	Photovoltaic
PVC	Polyvinyl chloride
PwC	PwC Australia
RAB	Regulatory asset base
RBA	Reserve Bank of Australia
RCM	Reliability centred maintenance
REFCL	Rapid earth fault current limiter
Repex	Replacement expenditure
Reset RIN	Price Reset Regulatory Information Notice
RFM	Roll forward model
RIN	Regulatory information notice
RIS	Regulatory Impact Statement
RIT-D	Regulatory investment test – distribution
Rules	National Electricity Rules
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SAMP	Strategic asset management plan
SCADA	Supervisory control and data acquisition
SFA	Stochastic Frontier Analysis
STPIS	Service Target Performance Incentive Scheme
SWER	Single wire earth return

TNSP	Transmission network service provider
TWG	Technical working group
UDV	United Dairyfarmers of Victoria
VBRC	Victorian Bushfires Royal Commission
VCR	Value of customer reliability
WPI	Wage price index

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