Powerco 2022 AMP Update

March 2022

Contents

1. Introduction

1.1 Purpose

Powerco is Aotearoa New Zealand's second largest electricity distribution company by customer numbers, supplying around one of every six residential customers in the country. We have the largest supply territory by area and largest overall network length. Our networks stretch across the North Island from the Coromandel to the Wairarapa.

We provide an essential service to more than 340,000 homes and businesses, serving approximately 900,000 customers. The electricity distribution assets we manage have long lives and are capital-intensive to create and maintain. We consider ourselves long-term asset stewards, providing effective and efficient asset planning and investment for current and future generations.

In March 2021, we published a comprehensive Asset Management Plan, which is available on our website www.powerco.co.nz. This Asset Management Plan Update (AMP Update) is limited to providing updates on material changes to the previous AMP, the latest information on our forecasts and on our long-term strategy for managing our electricity assets. We are experiencing some major shifts in our operating environment, requiring some substantial changes to our previously published plans and forecasts. These trends and our plans to respond are also highlighted in this AMP Update.

The 2022 AMP Update relates to the electricity distribution services supplied by Powerco and covers the planning period from 1 April 2022 to 31 March 2032.

1.2 Information disclosure requirements

Clause 2.6.3 in the Electricity Distribution Information Disclosure Determination 2012 requires Powerco to complete and publicly disclose, before 1 April 2022, an AMP Update.

Clause 2.6.5 states that the AMP Update must:

- Relate to the electricity distribution services supplied by the electricity distribution business (EDB)
- Identify any material changes to the network development plans disclosed in the last AMP (or AMP Update) per clause 11 of attachment A
- Identify any material changes to the lifecycle asset management (maintenance and renewal) plans disclosed in the last AMP (or AMP Update) per clause 12 of attachment A
- Provide the reasons for any material changes to the previous disclosures in the Report on Forecast Capital Expenditure set out in Schedule 11a and Report on Forecast Operational Expenditure set out in Schedule 11b
- Identify any changes to the asset management practices of the EDB that would affect Schedule 13 Report on Asset Management Maturity disclosure

In addition, Clause 2.6.6 requires each EDB to publicly disclose the following reports before the start of each disclosure year:

- The Report on Forecast Capital Expenditure in Schedule 11a
- The Report on Forecast Operational Expenditure in Schedule 11b
- The Report on Asset Condition in Schedule 12a
- The Report on Forecast Capacity in Schedule 12b
- The Report on Forecast Network Demand in Schedule 12c
- The Report on Forecast Interruptions and Duration in Schedule 12d

If an EDB has sub-networks, it must also complete the Report on Forecast Interruptions and Duration set out in Schedule 12d for each sub-network.

1. Introduction

1.3 Structure

This AMP Update has been structured to meet disclosure requirements and is in a similar format as our previous AMP updates. While it discusses the changes we foresee in our operating environment and how these affect our forecasts, in the interests of brevity we have not attempted to duplicate detailed explanations where these are already available in our previous, comprehensive AMP. We encourage readers to revert to our previous AMP if a greater level of detail is required.

Section 2 discusses our view of our emerging operating environment and how Powerco intends to position itself in this.

Section 3 provides commentary on the changes from our previous AMP to our planned construction, operational, and maintenance plans, as necessitated by our customers' evolving requirements and the changes we see in our future operation.

Section 4 provides an overview of aggregate forecast expenditure and outlines the changes that have materially affected our forecasts. It also provides information on material changes to the schedules since our previous disclosure.

Section 5 contains Schedules 11a – 12d, and 14a to meet information disclosure requirements.

Section 6 addresses the certification requirements for this disclosure.

2. A changing operating environment for electricity distributors

2. A changing operating environment for electricity distributors

2.1 Introduction

In our 2021 AMP we discussed the emergence or acceleration of a number of industry-wide trends that were shaping our longer-term planning for the electricity network. During FY22 these trends were not only affirmed but appear to be picking up momentum even faster than foreseen. In addition, there are some new factors emerging that, if sustained, would have a major bearing on our business.

In this section we review the major trends and external influences we identified in the previous AMP. We provide updates on how these played out during FY22 and also cover emerging trends - established or potential.

During FY22, we formulated a formal Powerco view on the future electricity operating environment. This has a direct bearing on our asset management and is therefore also discussed below.

2.2 Update on major electricity network operating trends

One year on, many of the trends identified in our 2021 AMP have generally accelerated and continue to have a major impact on our forward planning.

2.2.1 Ongoing network growth

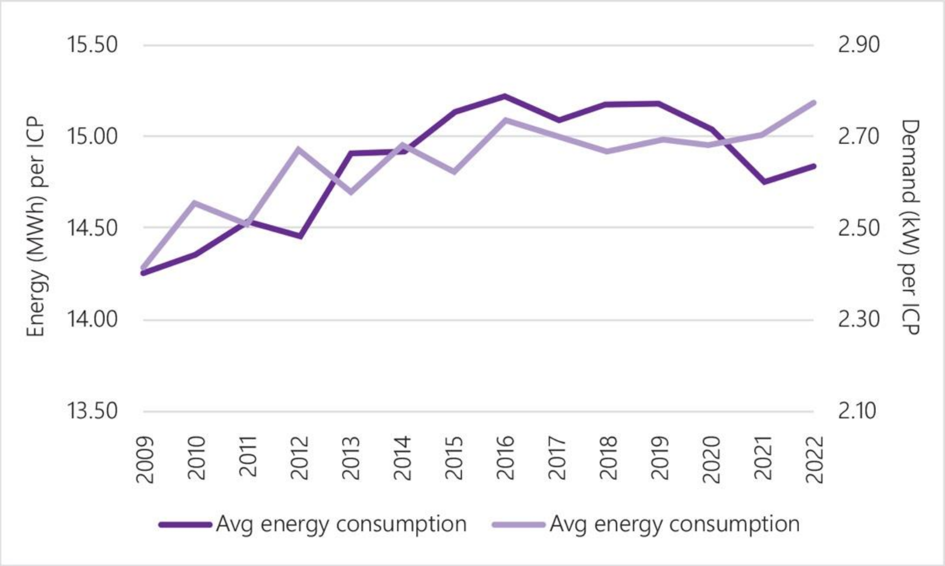
Customer demographics

- Population movements and other demographic trends remained largely as forecast in 2021. This is expected, as these trends are generally slow, with not much movement expected in a year. We are however seeing unprecedented connection activity (further discussed below), which suggests the potential for material population shifts in the near future.

Electricity consumption

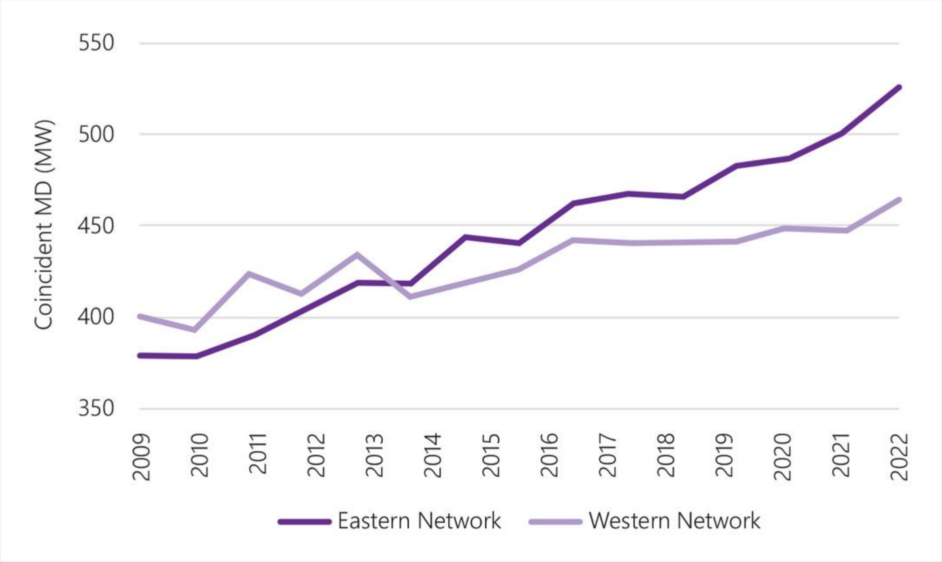
- At an aggregate level, average individual electricity consumption and individual demand on our network have remained relatively constant over the last decade. Over the last few years, we have observed changes due to the direct and indirect impacts of Covid-19 on how, when, and where electricity is consumed across different customer groups.
- Overall electricity demand continues to grow on the Powerco network. The coincident peak demand on the Powerco network in FY21 was at a record level – 986 MW compared with a previous high of 943 MW. This represents demand growth of almost 5%, in a year without exceptional cold spells. While year-on-year demand changes are very sensitive to short-term weather influences, this latest figure is in line with the long-term electricity demand growth we are observing.[1]

Figure 2.1: Average energy consumption and demand per ICP on our network



[1] Note that the energy consumption figures have been updated from those used in earlier AMPs, to correct for consumption at the Kinleith Mill between 2014 and 2017.

Figure 2.2: Peak demand growth on the Powerco networks East v West



Customer connections

Customer connection applications during 2021 were at unprecedented levels – large and small. The number of applications for new connections is 5% higher than our previous record (FY18) and, interestingly, the value of these applications is more than 30% higher than ever before. While some of this discrepancy can be ascribed to general cost increases (discussed further below), it also indicates that new connection requests are generally larger and more complex than in the past.

Large connection activity is particularly high. Over the last half of 2021 we have managed an opportunity pipeline with an average size of over 80 applications – compared with historical averages of around 6 to 7. While not all these applications are likely to carry through to actual connections, the likely impact on the network from those that do will be substantial, as indicated in the figures below. Should all the new and upgrade applications, excluding generation, proceed this could add up to 13% to our maximum network demand.

Figure 2.3: Large customer application numbers

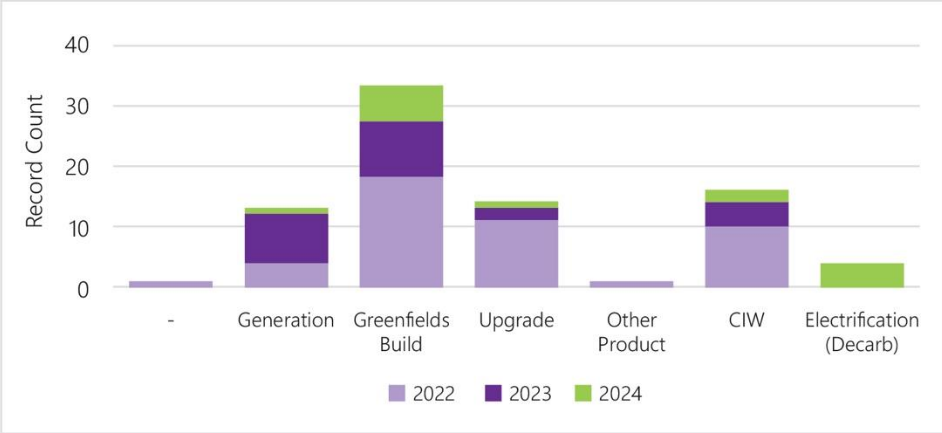
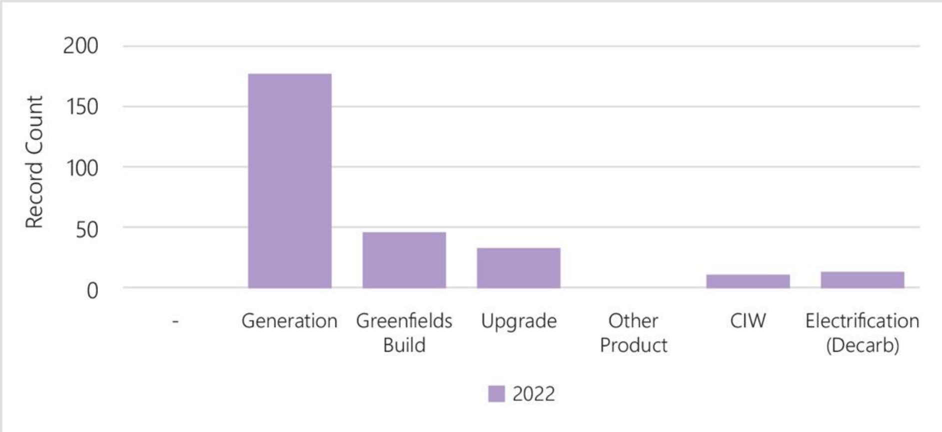
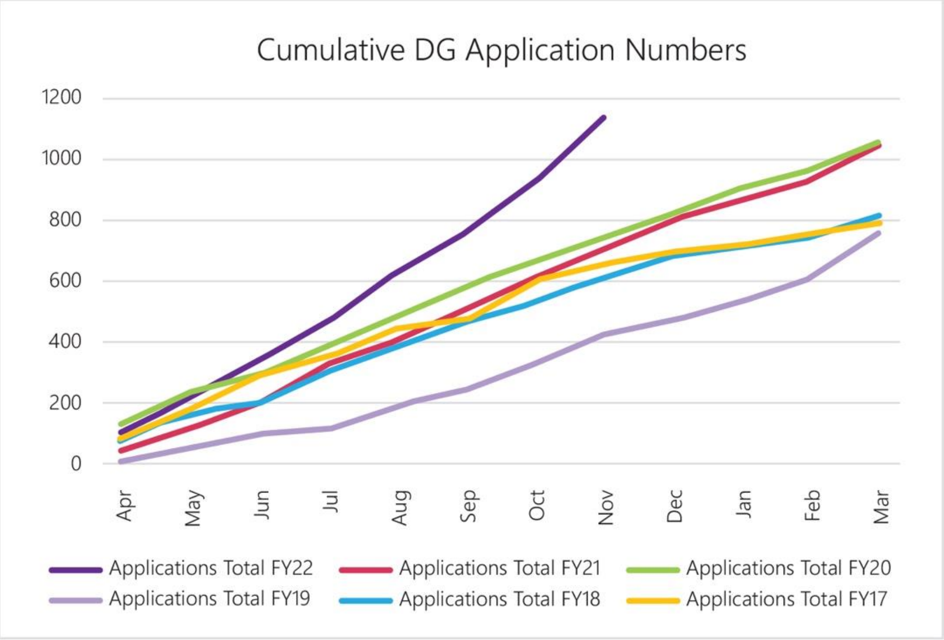


Figure 2.4: Large customer application size (MVA capacity)



- Of particular interest is the large volume of applications we are receiving for grid connected generation – predominantly solar PV farms. We currently have applications for around 170MW connected generation capacity being investigated, including solar farms exceeding 40MVA in size. By way of comparison, during FY21 we commissioned the Kapuni solar farm which, at 2MW, is currently still the largest in New Zealand.
- Similarly, small-scale distributed generation (mainly rooftop solar PV units) are also being installed at unprecedented numbers, as illustrated below.

Figure 2.5: Distributed generation application numbers



- Based on information available from Transpower and other EDBs, Powerco is not alone in seeing these unprecedented levels of customer activity on its network. Responding to these trends requires considerable network planning input (and design and project management once they proceed) and we are working on several actions to ensure that we can meet our customers' reasonable expectations for a timely, effective response.
- The distributed generation connections could have material customer and other market services benefits. We do note however that from a pure distribution network perspective, particularly in relation to demand management, their impact is expected to be more limited. The bulk of new generation is from solar PV, while the Powerco network peak is historically on winter evenings. Coupling solar PV generation with energy storage could change this dynamic, but at present rates the storage capacity provided is not material.

Energy hardship

- Energy hardship remains a concern across parts of our customer base. An important development in late 2021 was a change to the low-user fixed charge regulations that will see this scheme phased out by 2027. This will reduce some of the pricing distortions in play to treat consumption equally. Initiatives to address energy hardship can then be better targeted, including the winter energy payment which is in place today. We support the establishment of the Energy Hardship expert panel and other policy initiatives by MBIE in this area.

2.2.2 Legislative and electricity market influences

- **Reducing New Zealand's carbon footprint.** We are still awaiting the Government's Emissions Reduction Plan, which makes it difficult to assess and respond to future impacts of this with any certainty right now. However, given general expectations, we have seen an uptick in some activity.

- As noted, we are seeing unprecedented levels of interest in distributed generation connections, particularly solar PV.
- A subsidy for electric vehicles priced less than $80k was announced during the FY22. This has not yet had a marked impact and EV uptake trends have not materially accelerated. We anticipate that this will change, as more incentives supporting EVs are introduced.
- We observe increasing customer interest in the potential decarbonisation of heat processes. This is particularly for smaller, lower temperature applications where electricity can prove an attractive substitute for fossil fuels. This is potentially a major driver of increased future electricity demand.
- There has been a lot of interest shown in hydrogen as an alternative fuel source, but we have yet to see much tangible arising from this. We will continue to follow these developments and assess potential impacts on the electricity network.

- **Electricity regulation.** While there have not been any material changes to electricity distribution regulation during FY22, the Electricity Authority has been particularly active. It is progressing discussions on the future role of distribution networks in the electricity market and also in promoting reforms to electricity distribution pricing. We generally support the intent and direction of these discussions and will continue to engage constructively in setting the future direction of the market.
  - The Commerce Commission is looking into the potential impact of decarbonisation on electricity networks as part of the review of input methodologies. It is clearly a very important area with a potentially large impact on all aspects of the electricity supply chain, particularly for industrial customers. We will continue to engage constructively on developing effective, equitable solutions to the opportunities and challenges decarbonising will bring.

2.2.3 Technological changes

The rate of technology evolution has steadily increased during FY22, despite logistical challenges resulting from Covid-19 limitations.

Network technology trials

On the network side, we are conducting trials in several emerging technology areas, including the following.

- **Electric Vehicles** – installation of 80 EV chargers to assess their impact on maximum household demand at peak network use times and the potential for influencing customer behaviour.
- **Internet of Things (IoT)** – establishment of a network-wide LoRaWAN communications network including field-based devices, supporting communications infrastructure and data standards.
- **LV Monitoring** – installation of approximately 300 LoRaWAN-based devices that monitor voltage/current to provide real-time visibility of network performance.
- **Fault anticipation** – installation of ten devices that monitor high-frequencies signals on conductors to identify network issues (e.g., vegetation overgrowth, line clash, cracks in conductor, etc.) to provide notification before a fault is encountered.
- **Wireless Power Transmission** – a future technology trial testing the transmission of power via radio frequency. A laboratory trial was completed successfully, and a field trial is planned next.
- **Smart Grid Trial** – the upcoming installation of distributed energy resources (DER) in a suburb to assess the impact of DER on network performance and to test various energy management software solutions.

- Network Model – creation of an accurate, exhaustive electronic version of the physical electrical network and associated data requirements and standards.

The overall intent of our technology trials is threefold:

  - Seeking opportunities where new technology can reduce the cost of electricity distribution, through providing more effective network solutions or improved utilisation of our network
  - Improving our customers' experience, through improved network reliability and resilience, better power quality and faster response to events

- Supporting the integration of distributed energy resources onto the network while ensuring its ongoing stable and safe operation.

We have developed a network transformation roadmap, which is summarised in the sunray diagram below. This guides our selection of trials and pilot programs for new technology. Importantly, we see collaboration and free information interchange with customers, other EDBs, academia and industry participants as key to network transformation – this work should be for the benefit of the whole of Aotearoa New Zealand.

Market driven solutions

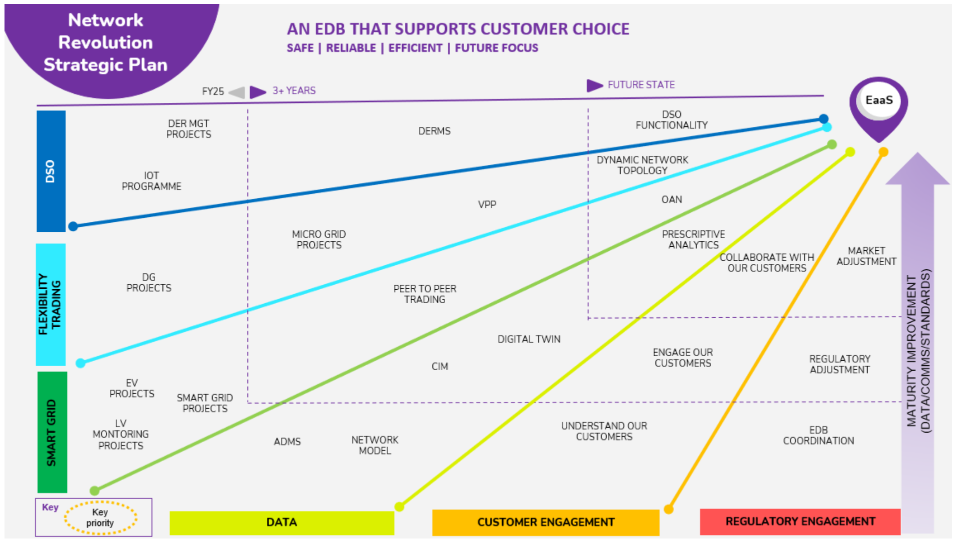
Powerco recognises that with changing technology, there are increasing opportunities to provide network solutions though non-traditional means and also that these solutions could be effectively provided by third parties. Accordingly, we have adopted an approach whereby, where practical and of suitable size, we will request proposals from the market for solutions as an alternative to network extensions or large rebuilds. Where offers received are practical and economically beneficial, these are adopted.

So far, we have issued such requests for three large developments and, although suitable alternatives were only received on one of these, will continue to do so in future.

Customer technology

While the uptake of new technology by customers is increasing, the impact of this on our network operation is not yet material. We continue to monitor trends and remain committed to working closely with our customers to ensure the minimum possible restrictions on their use of our networks for whatever application they require. This is the foundation of an open access network, one of our core planning principles.

Figure 2.6: Powerco's network evolution strategy-on-a-page



Based on publicly available information[2], the price for installed solar PV household installations and battery storage systems appears to have levelled off. This follows years of substantial reductions, particularly in the price per kW for PV installations.

The indicative price of solar PV, battery storage and the uptake rates for solar PV installations on our network are illustrated below.

Figure 2.7: Battery storage price index

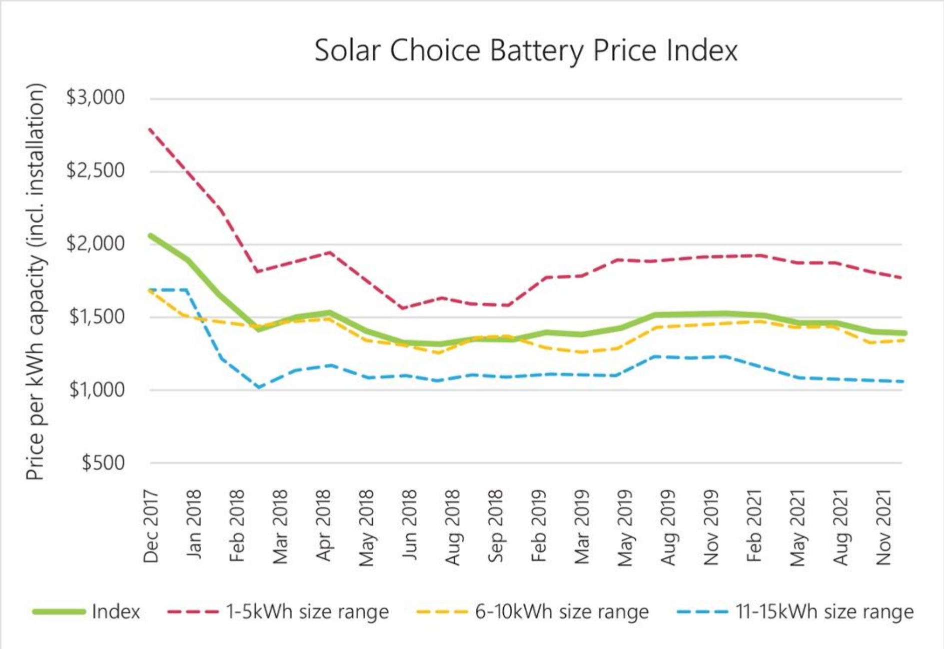
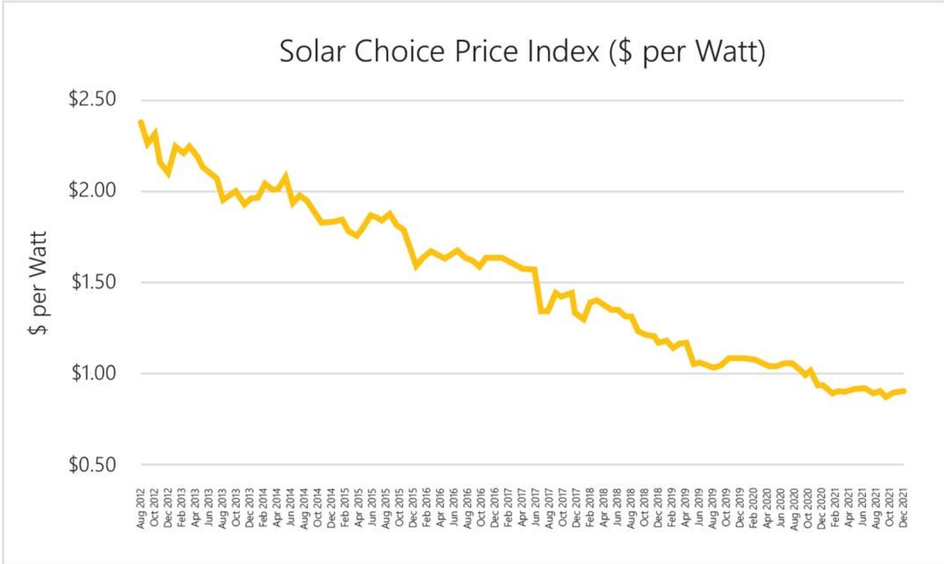
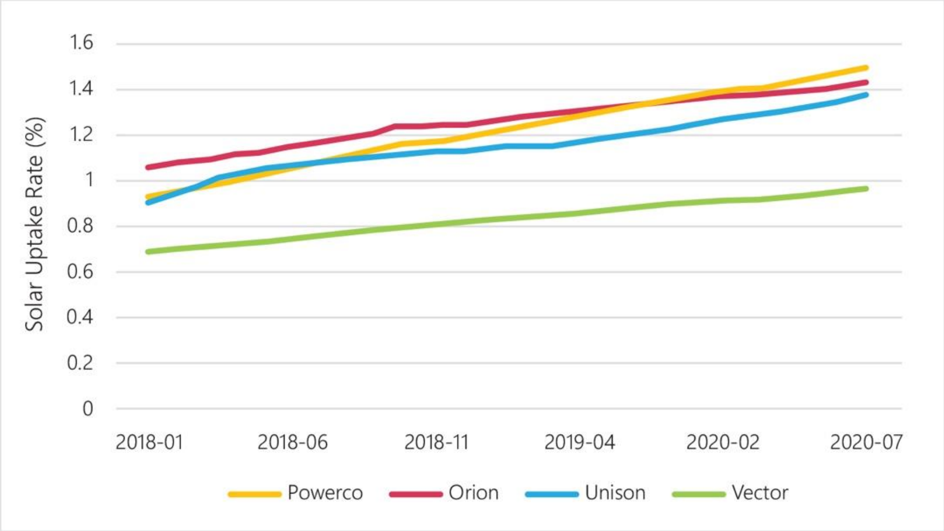


Figure 2.8: Solar PV price index



[2] In the absence of freely available information on New Zealand price movements, we rely on an Australian source.

Figure 2.9: New Zealand EDB solar uptake rates (% of customer base)



2.2.4 Managing Powerco's greenhouse gas emissions

Powerco annually publishes its full audited greenhouse gas emissions inventory report on its website. Our reported greenhouse gas footprint increased during FY21. This was largely due to improved reporting of our emissions (including emissions from diesel generators used to supplement our network) and changes in the national grid energy mix (the type of power generation used). Additionally, although the impacts of Covid-19 and restricted business travel helped to decrease our emissions, this was offset by an increase in emissions from purchased goods and services due to an increased electricity network works programme.

During FY21, Powerco developed its first emissions reduction roadmap to achieve a net-zero carbon emissions target by 2030. This is now in the process of being implemented. Compared to our base year of FY19, we have seen emissions reductions due to:

- Decreased use of vehicle fuel
- Improved recycling of office waste
- Reductions in electricity use
- Less business travel

Some of the future improvements Powerco is working on to reduce its emissions, include the following:

- Further reductions in travel and increasing reliance on remote meeting facilities
- Further reductions in electricity use at our substations and office facilities
- Further reductions in office waste going to landfill
- Ensuring we source our assets from responsible suppliers, using sustainably sourced materials
- Improving our understanding of the embedded carbon in our network and maximising the knowledge gained. Carbon embedded in the materials used to build (eg concrete v wood poles) and operate (eg ester v mineral oils) our network has an impact on our footprint
- Increasing automation and remote fault indication on our network, thereby reducing the travel required for switching, fault-finding and repairs
- We are in the process of re-introducing wooden poles in our more rural network areas, instead of the concrete poles currently used. This is expected to lead to material carbon emission reductions, both in the installation and the manufacturing of the poles.

- Investigation of alternatives to diesel fuel or technological changes that disrupt generator requirements

2.2.5 Impact of Covid-19

Superficially, Covid-19 has had relatively little impact on Powerco's operations during FY21. While additional safety measures were put into place, our construction and maintenance programmes were delivered to plan. As the pandemic continues, we continue to closely monitor the situation and respond as required to ensure the safety of our staff and service providers, also ensuring the ongoing operation of our control centre.

On a more macro level, Covid-19 responses and associated lifestyle changes continue to have a material impact on how we plan our electricity network. Lockdowns and increased working from home, even intermittently, lead to a higher than traditional reliance on reliable electricity and communications. Accordingly, we must enhance security of supply to residential areas, particularly in our low voltage networks.

Also associated with Covid-19 restrictions, we are experiencing logistical constraints on the delivery of imported goods. Supply chains are under pressure, leading to delays in delivery and much increased transport cost. In addition, major manufacturing delays are experienced for certain equipment types, especially those involving electronic controls.

More recent emerging factors

During FY21, new factors emerged that have a material bearing on our operations. It is not yet clear that these will be long-term, but for the foreseeable future we will have to manage these trends. It is also not clear to what extent the Covid-19 pandemic and responses to it have led to the changes.

2.2.6 Shortage of skilled labour

Towards the latter half of FY21, it has become noticeably harder to recruit skilled staff, particularly in technical areas. This appears to be largely because of resource shortages, rather than any intrinsic bias against utility (or electricity) business or Powerco in particular. There also appears to be more fluidity in the employment market, with an increased number of staff shifting between companies. Anecdotally, our peers at other EDBs are experiencing the same concerns and difficulties in finding resources.

The shortage is likely to be partly driven by the sudden, major drop in immigration numbers for skilled workers, which in turn is likely from a combination of a deliberate immigration policy and Covid-19 related response measures. It may also reflect increased construction activity across the market, with an associated draw on the available pool of skilled resources in New Zealand.

The difficulty in finding skilled resources is of concern to Powerco. We are facing a considerable uplift in customer-driven work, including large generation applications, and also expect a major uptick in work resulting from customer decarbonisation initiatives. Accordingly, we are looking at several initiatives, including accelerating and extending our graduate intake programme, reprioritising internal initiatives and working on more efficient processes.

2.2.7 Increasing reliance on secure electricity

As noted above, there is an increasing need to enhance the reliability of supply to customers changing their traditional working patterns, or who face periodical lockdowns at home. Reliance on electricity is anticipated to increase even more as decarbonisation initiatives take off. A large proportion of New Zealand's plans to reduce carbon emissions relies on substituting other forms of fuel with electricity, for areas such as transport, space and water heating, industrial processes and cooking.

2. A changing operating environment for electricity distributors

Supporting the increased reliance on secure electricity means that we must rethink our network designs and build in more redundancy and resilience. This will have to extend right through to our low voltage networks, which have traditionally not received the same level of focus as the higher voltage networks.

Such redundancy will in part be provided by conventional electricity distribution infrastructure but can also be enhanced through non-network solutions such as distributed generation, automation or demand management. Effectively integrating network solutions with non-traditional energy solutions represents a major shift of focus for us over the coming years.

2.2.8 Cost pressure

The increase in New Zealand's inflation rate over the last year is widely recognised. We are experiencing an even higher rate of price increases in electricity construction work, resulting from increasing materials costs, especially imported, as well as higher labour costs. High volumes of work mean increased costs from consulting and project management resources as well as service providers.

Given that CPP revenue settings were based on a much lower forecast inflation rate than we are experiencing, this means that we have to cut back on our planned construction work to remain within regulatory settings.

2.2.9 Delivery delays

The impact of Covid-19 restrictions on international logistics is also widely recognised. While we have not had to curtail any work because of an inability to source equipment, we have been seeing major delivery delays. This is especially the case for sophisticated equipment, requiring electronic controls. These delays are impacting on our major project delivery.

2.3 Where is electricity demand on our network heading?

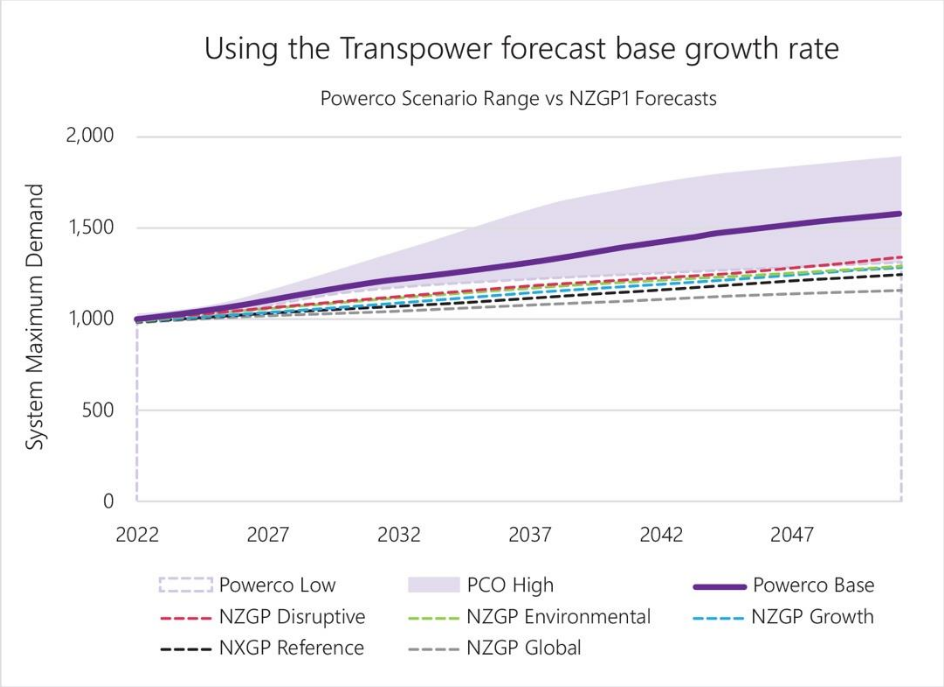
Powerco has undertaken considerable work during FY21 to refine its longer-term electricity demand forecasts. Our updated, network-wide view is shown below. These forecasts are very sensitive to the future trends discussed above which are by themselves uncertain. To accommodate this, we have adopted a forecast range, based on a base case, high and low scenarios.

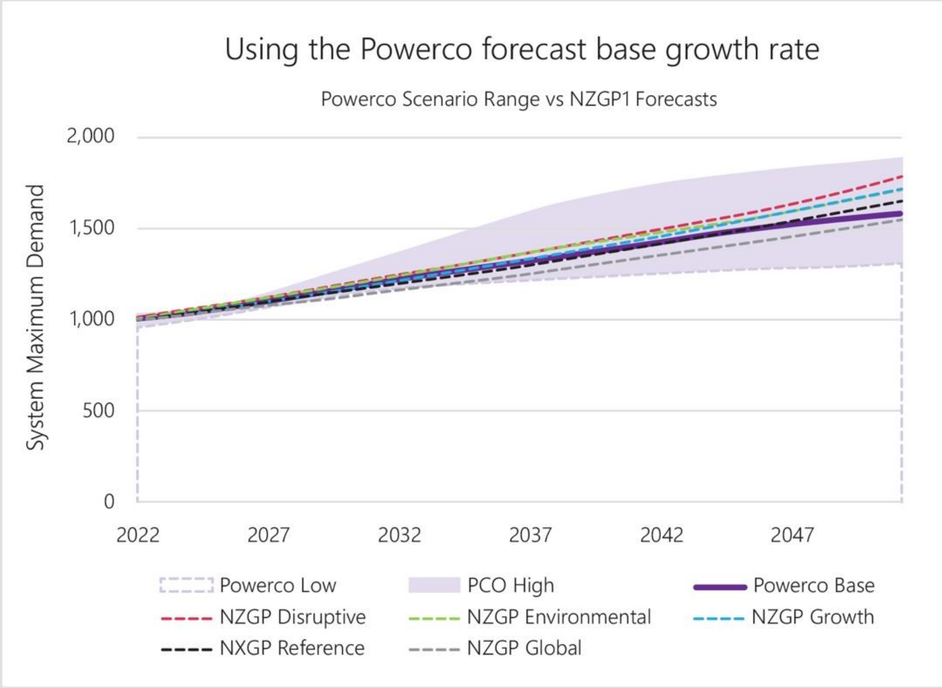
By way of comparison, we also illustrate Transpower's Net Zero Grid Pathways 1 (NZGP1) grid planning scenario update, published in December 2021[3], using its forecast growth rates applied to Powerco's 2021 peak demand. The NZGP1 scenarios are in turn a variation on the Ministry of Business, Innovation and the Environment (MBIE) Electricity Demand and Generation Scenarios (EDGS 2019).

We note that Transpower assumes a substantially lower organic growth rate (around 0.3% per year) compared with what we have been experiencing on the Powerco network (around 1.3% per year historically, more recently around 1.5%). To enhance the comparison, we also include a figure where our base growth rate is superimposed on Transpower's other growth assumptions.

[3] "NZGP1 Scenarios Update", Transpower New Zealand Ltd, December 2021

Figure 2.10: Powerco demand forecast range compared with NZGP1





There are five key factors[4] driving the variances in our demand forecast range. Assumptions related to these are also behind the differences between Transpower's and our own forecast growth rates.

- Likely to add electricity demand:
  - Organic growth in electricity demand
  - Uptake and use of electric vehicles

[4] Events like a major natural disaster, war or widespread economic decline could of course also significantly impact electricity consumption. However, not only are such events rare and cannot be reasonably foreseen, but to plan network investments for these scenarios would imply shrinking network investment which would materially compromise network capacity and general economic and household activity under normal operating condition.

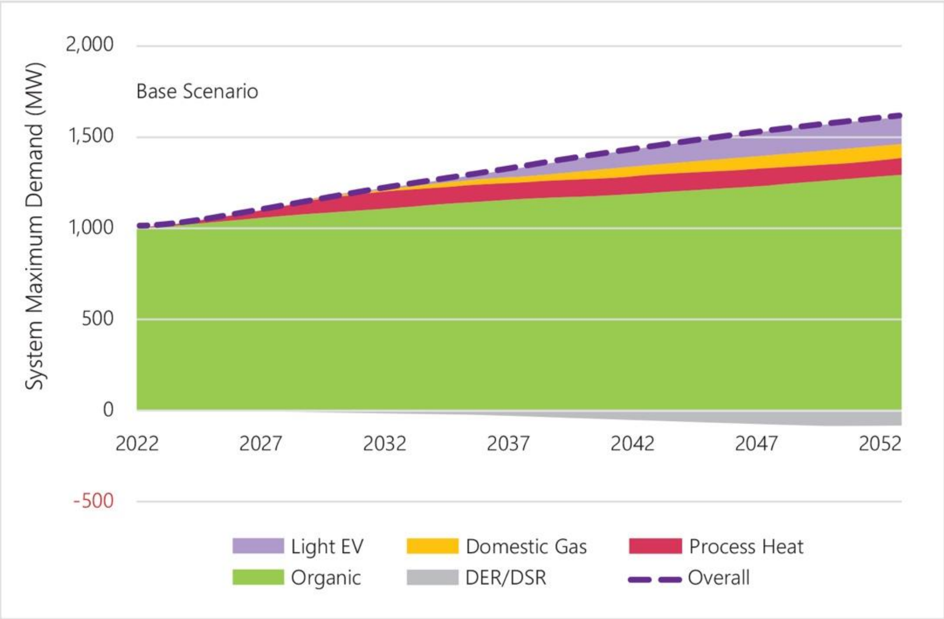
- Decarbonisation of carbon-based industrial processes, particularly lower temperature heat processes
- Potential phasing out of natural gas reticulation

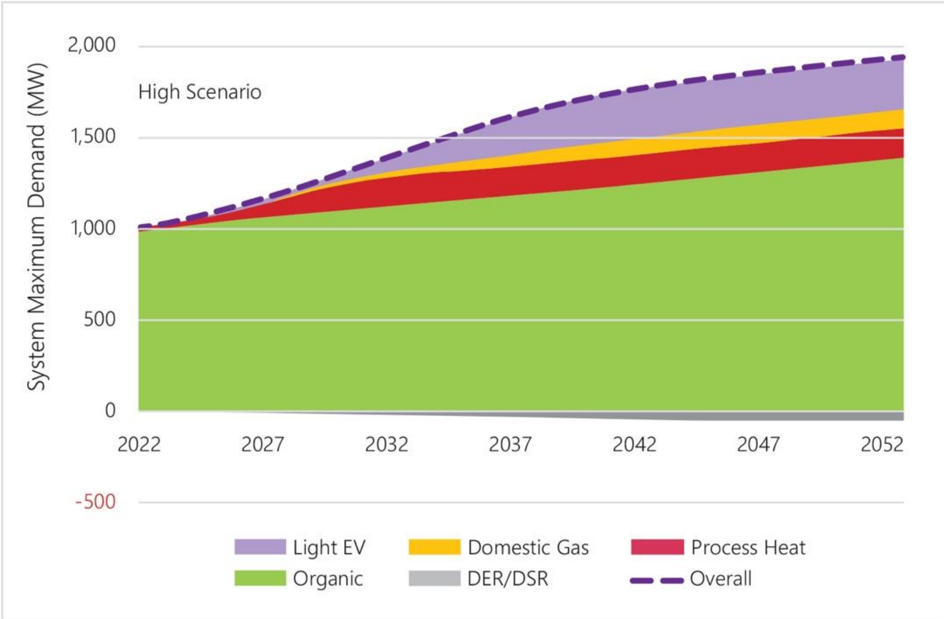
Likely to reduce demand:

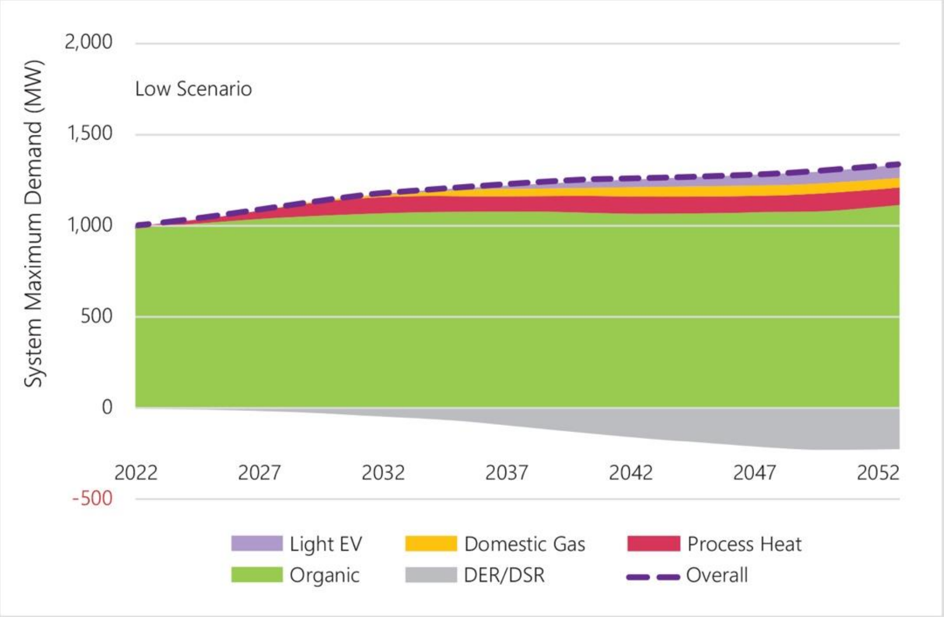
- Increased uptake of distributed energy resources, such as local generation, energy storage or demand management

The forecast impact of these factors on our demand forecast scenarios is shown in the following figures.

Figure 2.11: Powerco demand forecast ranges







Our demand forecast differs from the NZGP1 range primarily for the following reasons:

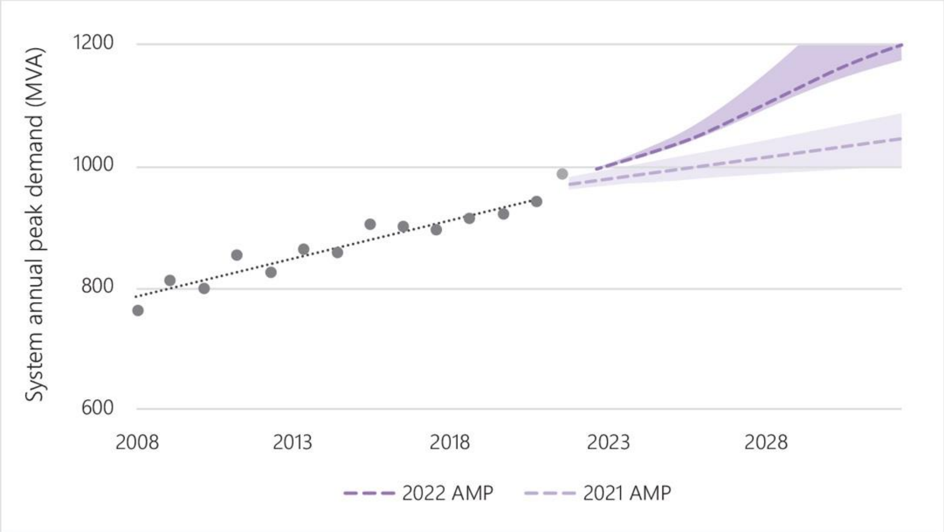
- **Organic (base) growth**. As noted above, the base demand growth rate on our network has for an extended period been consistently higher than the country-wide average seen by Transpower. For our forecast, we have assumed a year-on-year base growth rate of 1.3%.
- **Electric vehicle charging**. Our EV use-assumptions are somewhat more aggressive than those adopted by Transpower. This is mainly a result of our assumptions of average travel distance per day (e.g. 40km, for our High scenario only, vs 30km for Transpower) and the success of incentives or controls to shift EV charging to off-peak periods. Transpower envisages most charging will take place outside peak demand periods, while we allow for a 20% increase in the MD of an installation in our base case scenario.
- **Phasing out of reticulated gas networks.** Final details are sketchy, but there has been a proposal by the Government to phase out natural gas use[5]. We assume that this energy will be largely replaced by grid-supplied electricity and have allowed for this in our forecast (with the impact likely to be felt later in the forecast period than that of the other demand factors).

For our AMP planning purposes, we have adopted the base case growth forecast. As shown below, this is higher than the forecast used for the 2021 AMP, and the changes have been reflected in our planning and resulting expenditure forecasts.

[5] The proposal might relate to industrial, high-end use only, but based on our understanding of the economics of gas distribution, the resulting reduction in the volume of gas distributed will likely make it uneconomic to continue with producing and reticulating gas to residential areas.

2. A changing operating environment for electricity distributors

Figure 2.12: Changes in our AMP demand forecast ranges



We are strongly of the view that, in a growth scenario, it is important to make infrastructure available potentially slightly ahead of actual need, rather than run the risk of delays in meeting customer requirements.

- There is a significant asymmetry in the economic impact to society between (small) over- and under-investment in infrastructure, and electricity in particular. Over-investment has additional customer cost associated with recovering the investment on assets built some time before they're fully utilised. Conversely, not having capacity available when required could have economic and societal impacts of a much larger magnitude. For example, there may be enforced delays in commercial, industrial or residential developments, or customers may suffer the consequences of poor supply reliability when sufficient redundancy cannot be maintained.
- In addition, New Zealand's pathway to carbon neutrality will depend to a substantial degree on electrification – for industrial processes, transport and residential or commercial use. The inability of the electricity system to deliver the capacity for this will significantly impede or delay decarbonisation.

Our base case scenario therefore reflects a slight bias towards higher future demand expectations, which we believe is appropriate to address this asymmetry risk. We review our forecasting assumptions on a regular basis and will continue to adapt our longer-term investment plans as new information about actual growth patterns come to light. Most major electricity distribution network infrastructure investments, particularly growth-related investment, require around three to five years to deliver – heavily influenced by the time required to obtain land and the necessary resource consent or easements for line routes and substations. This implies that we must adopt a relatively firm forward demand view for at least this period.

It should be noted that when it becomes apparent that customer growth needs on any part of our network are likely to exceed capacity within the planning window, our first response is always to test whether sufficient capacity can be securely made available through minor tweaks to existing infrastructure or changing operating practices. Following that, we consider whether feasible options exist to defer major investment, typically though applying non-network solutions, incremental network investments, or seeking alternative capacity proposals on the wider market. Only if these options are not economical or practical, do we proceed to plan major network investments.

3. Our 2022 Asset management plan update

3. Our 2022 asset management plan update

3.1 Introduction

This Asset Management Plan Update (AMP Update) provides a refresh of key planning outputs for the next 10 years. Our asset management plan is an essential part of our long-term asset planning and investment framework. The AMP Update is primarily informed by our 2021 Asset Management Plan, which we published one year ago. At the heart of this were three key commitments for the future of our electricity network:

- **Ensuring safe and resilient networks**: stabilising the underlying condition and performance of our asset fleets through asset renewal, maintenance and vegetation programmes and making sure that our assets do not pose an unacceptable safety risk to the public, our staff or our service providers
- **Supporting growth in our communities**: allowing for growth in electricity demand and provide sufficient redundancy by investing in new and upgraded assets
- **Enabling our customers' energy choices**: ensuring our customers can connect increasing volumes of new technology to our network (such as electric vehicles and photovoltaic cells), while we will manage the increasing complexity this could bring to operating a distribution network.

These commitments are driven by our customers' expressed preferences, which sit at the heart of our decision making. Electricity is a key enabler for economic prosperity and a modern lifestyle and, as such, it is essential that we continue to invest in our assets to meet the needs of our customers in the long term.

We also recognise that society is facing an unprecedented challenge regarding a warming environment. Minimising carbon emissions is a key priority for Aotearoa New Zealand and, by implication, for our customers. As a company, we are fully committed to helping New Zealand achieve its carbon reduction targets agreed to in terms of the Paris Accord (2015), and the Government's associated target of a 100% renewable energy supply by 2035. We are committed to acting in an environmentally responsible manner in all our investment decisions and operational practices – as witnessed by our recent certification to the ISO 14001[6] standard and our high GRESB[7] score.

However, our impact on carbon reduction is insignificant compared with what we can help our customers, including generators, achieve – through our role in enabling them to create, use and save energy as efficiently as possible. The key to us supporting New Zealand's carbon reduction targets will be running our network to open-access principles, offering maximum flexibility to customers with the opportunity to innovate, connect to, and transact over our network without impediment. While future energy market arrangements are still being developed, we will ensure that the network remains safe, operates stably and provides sufficient capacity under any reasonable energy use and market scenario.

3.2 Our customised price-quality path

Since April 2018 we have been operating under a five-year customised price-quality path (CPP), following approval of our application to the Commerce Commission. We are now four years into this period. For the first year of this AMP Update therefore, the focus is on completing the delivery of our CPP commitments.

Sitting at the heart of our CPP application was analysis that indicated we had significant challenges to address in the future. These included large increases in the number of assets that were approaching end-of-life and where performance was deteriorating, ongoing demand growth in the communities we serve, and increased complexity associated with ensuring stable network operation in a changing energy environment. Therefore, it became necessary to seek permission

[6] ISO 14001 is an internationally accepted standard that provides the framework to put an effective environmental management system in place within an organisation.

[7] GRESB is an independent environmental, social and governance benchmark for real assets, defining the global standard for sustainability performance in real assets to assess the sustainability performance of real estate and infrastructure portfolios and assets worldwide.

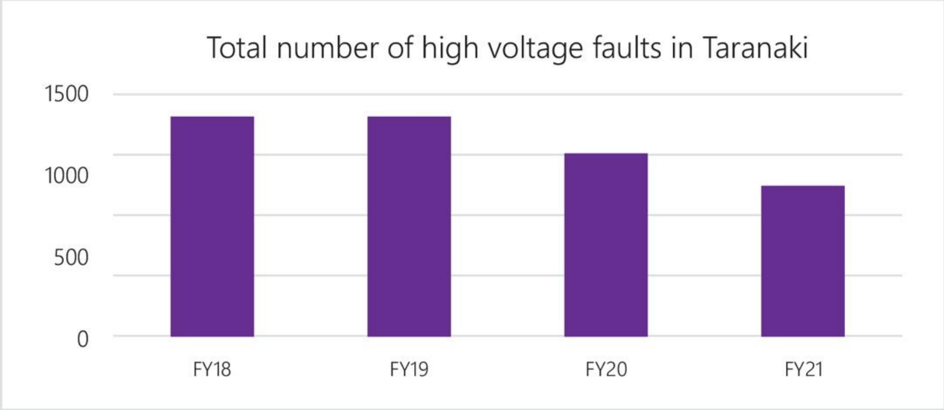
from the Commerce Commission to raise prices to fund much needed renewals and network upgrades.

We take the delivery of our CPP very seriously. The programme is essential to fulfil our commitment to our customers to provide them a safe, secure and resilient network, and we also recognise our responsibility to our customers to optimise the value from the increased expenditure. In September 2019 we published our first annual delivery report (ADR) for year one of our CPP, called "Delivering on our promise". We shared the ADR with customers and stakeholders through various events, leaflets, webinars and social media. Our CPP is for our customers, so we sought out feedback on our delivery so far. An updated ADR has been published every year since then. You can keep track of our CPP delivery at www.powercodelivering.co.nz.

During FY21 we have once again had some major achievements:

- Network renewals were completed to plan and (CPP) budget
- Network maintenance was conducted to plan and (CPP) budget
- We achieved provisional ISO55001 certification for our asset management practices
- Defect numbers were substantially reduced, particularly those ranked more critically
- The initial phases of the LIDAR and pole-top photography programmes were successfully delivered
- Defective equipment faults are trending down, as illustrated in the example below

Figure 3.1: Changes in our AMP demand forecast ranges



We are now in the final phase of delivering to our CPP programme. After the successful acceleration and embedding of our asset renewal, maintenance and defects activities, the emphasis for this final period is on delivering the remaining major projects approved as part of our CPP revenue allowance. We must manage this against a challenging background of increasing material and construction costs, the complexities of obtaining line routes and resource consents and the delays in delivering major equipment. A large proportion of these major works are scheduled for commissioning during the last quarter of FY23.

3.3 Relooking at the bulk electricity supplies to our regions

During FY21 we kicked off a joint project with Transpower to investigate the longer-term bulk supply requirements for the eastern Bay of Plenty region. This is an area of major growth on the Powerco network, where we have seen demand growing at rates that suggest the bulk supply capacity will need to be upgraded in the medium-term future.

Based on aligning demand forecasts for the region and joint modelling by Powerco and Transpower, early results make it clear that the region is indeed facing progressive potential security of supply problems over the next decade. The modelling is being finalised, but we have already started work on identifying the optimal location for additional bulk electricity supply and how the Powerco sub-transmission network may need to be reconfigured to accommodate this. This will in turn be presented to Transpower for feasibility studies before a joint upgrade plan is finalised.

Following the Bay of Plenty study, we are planning to conduct a similar review of the Thames Valley region.

3.4 Our next asset management plan

We are already beginning work on our next AMP, to be published prior to 1 April 2023. This will be a comprehensive plan, in which we will undertake a thorough refresh of our asset strategies and long-term forecasts. As such, it will reflect our latest updated demand forecasts, an up-to-date understanding of how the operational trends discussed above are playing out, updated bulk supply plans and any other pertinent information from the next 12 months.

This will also be our first post-CPP asset management plan. At the time this plan is being finalised, we will have visibility of our DPP settings approved by the Commission – an area of considerable uncertainty at the moment.

It will therefore lay out how we intent to prioritise investment and operate our network under the DPP.

There are several drivers of future investment we will continue to examine in detail over the next 12 months, in preparation for the 2023 AMP. These include:

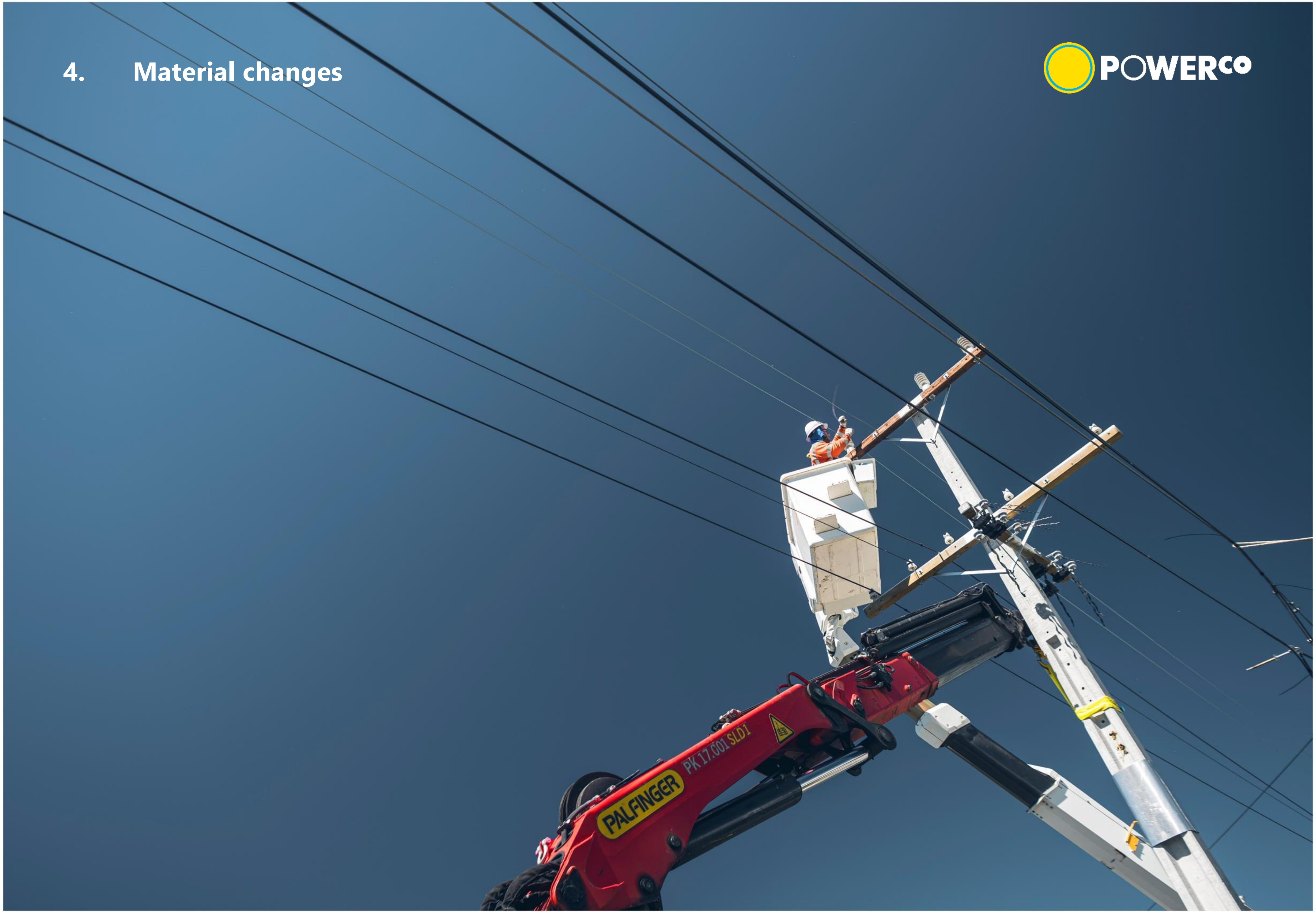
- Improved **customer intelligence**: Our distribution network exists to serve our customers. We continue to work hard to improve our understanding of the service our customers expect from our network, and how this varies across the different parts of our network. Improved customer intelligence will be the basis of informed discussions around price/quality trade-off preferences, which feed into our investment decisions, drive the application of more granular network performance standards, support more accurate price signals, and ultimately impact network architecture decisions.
- Ongoing focus on **safety-in-design**: One of the most effective factors in ensuring the safe roll-out and operation of our assets, is to explicitly build in safety during the planning, asset selection and design stages of a project. Powerco is continually developing its capabilities in this regard, also seeking and incorporating feedback from our service providers and operators that help us improve our designs.
- Enhancing our **open access network**: We have previously signalled that we believe the best way to support our customers' future requirements for a flexible electricity distribution network and expanded service offering, is to ensure that we continue to provide and enhance an open access network. What this means is our customers and other industry participants would be largely unconstrained in what they can connect to our network and in how they can use the network to support energy transactions. Our network transformation programme includes technology trials and research to ensure we are ready maintain and build an open access network – while ensuring that we can continue to provide a safe, stable and efficient supply. This will likely culminate in more widespread adoption of new technologies later in the planning period.

3. Our 2022 asset management plan update

- Supporting improved **sustainability**: We are committed to operating in an environmentally and socially sustainable way. Minimising our own carbon footprint is just one aspect of our sustainability efforts. However, even more importantly, as our own energy use and the environmental impact of our assets is relatively low, we can make a major contribution to our society's decarbonisation efforts through effectively planning and operating the electricity distribution network to allow customers to minimise their (collective) carbon footprint. One of our major planned activities for FY23 is to develop intelligence on our larger customers' decarbonisation plans, working jointly with EECA and Transpower, supported by DETA consultants. This will form the basis for future engagement around how we can best support their plans, developing optimal network, and non-network, solutions.
- Increasing use of **network automation, communication and monitoring**: Network technology is rapidly changing, particularly in the areas of automation, communication and monitoring. Functionality that was previously cost-prohibitive (or unavailable) is now more readily affordable, such as low cost LoRaWAN8 communication networks and many types of sensors. A roll-out of a LoRaWAN network across the Powerco footprint commenced in FY22, which will continue in FY23. The next phase will involve research and analysis on various network and asset sensors that will be rolled out and connected to this network – forming a key platform for our Internet of Things strategy. Automation improvements will enable us to make reliability improvements where appropriate, or better stabilise reliability in parts of the network where asset condition is degrading, without incurring the high costs associated with conventional network renewal.
- Evolving our **network operation technology**: We are evolving our existing SCADA and OMS systems to an advanced distribution management system (ADMS), as an enabler to an open access network and to improve the efficiency and effectiveness of our operations. The first phase of this project will be completed in FY23, but several further phases are to follow.
- Investment in **resilience**: Electricity is an essential resource for our communities, with ever-increasing importance as has been amply demonstrated throughout the lockdown periods associated with the Covid-19 response. With the impacts of climate change becoming more pronounced, increasing both the frequency and severity of weather events, coupled with our customers' ever-increasing reliance on electricity, this issue is likely to escalate even more in importance in the future. We have already undertaken investments to improve resilience against storms and other major events, such as the seismic strengthening of our zone substation buildings or increasing the designed strength of our assets in areas exposed to major weather patterns. However, it is an area that needs more development, and we are examining further programmes to improve our network's resilience. This includes ongoing reviews of our holdings of strategic spares, looking at increased storm hardening of our overhead line network, redesigning parts of our network with high criticality or vulnerable assets, or looking at local generation and energy storage to avoid outages when normal supply is compromised. Resilience to cyber threats is also a growing concern, and our cyber security programmes are increasing our corporate and network resilience.

[8] LoRaWAN is a low-power wide area network technology, that enables low-bandwidth communication to and from low-cost sensors.

4. Material changes



4. Material changes

Schedules 11a-12d are included in section 4. This section provides an overview of the rationale for changes since last year to our forecasts and the information provided in these schedules, as well as material changes to network development plans, asset lifecycle plans and asset management practices. However, in general, our previously disclosed views related to expenditure forecasts, asset condition, forecast capacity, forecast demand, and forecast interruptions remains consistent with that included in our 2021 AMP Update, subject only to minor refinement. We believe these forecasts continue to provide a realistic view of Powerco's future investment requirements and network performance.

4.1 Network development plans

There are no material changes to our network development plans, relative to our 2021 AMP, other than some changes to our Major and Minor projects which are discussed below.

4.1.1 Major Projects

- Whenuakite – this project has been deferred beyond the current planning period, following significant cost increases due to the poor geotechnical conditions of the overhead line pole foundations. We are now investigating potential non-network options to support network security in the Cooks Beach, Hahei and Hot Water Beach areas, such as from distributed generation or third party provided solutions.
- Matarangi – this project has been deferred beyond the current planning period as the full 66kV line/cable route has yet to be secured. The network issues at Matarangi will now be resolved via the Coromandel area generation project (see below), and the new Matarangi zone substation remains a long-term solution depending on demand growth in the area.
- Kopu-Tairua – as already identified in prior AMPs, this project has experienced significant cost increases since initially estimated for the CPP proposal. The network issues on the Kopu-Tairua circuit will now be mostly resolved via the Coromandel area generation project (see below), with additional third-party network support also being progressed to fully resolve this constraint. The original line upgrade has been deferred to beyond the planning period.
- Coromandel area generation – in response to challenges with the Matarangi and Kopu-Tairua projects (see above), a new Major Project has been scoped for the Coromandel area. Generation is planned to be installed at Coromandel township and Matarangi and will operate to provide a backup supply to Coromandel township, reduce peak demands at Matarangi and the Kopu-Tairua circuit following potential contingent events at peak demand times. The generation is planned to be commissioned by the end of FY23.
- Kaimarama – changes to the National Environment Standards (NES) in late 2020 have introduced strong protections for wetland areas, which were subsequently identified near our planned switching station site. Consenting challenges forced us to abandon our planned site, following advice from the Waikato Regional Council. We are now exploring alternative sites in the area where the switching station construction can be staged.
- Kerepehi backup supply – the generation backup option concept design has been completed but following a review of the overall Major Projects portfolio this project has been deferred to FY24-25 due to its lower priority.

4.1.2 Minor Projects

- Peat St to Taupo Quay cable – this project was outlined in the last AMP alongside other potential issues to reinforce the security of the Whanganui 33kV ring. This project is now the preferred solution and is planned for commissioning in FY23 (in place of the original Whangangui GXP to Taupo Quay cable project outlined in CPP).
- Matatoki second transformer – following the deferral of the Whenuakite Major Project (see above), this project has been brought forward to FY23 to utilise the transformer ordered for Whenuakite.

4. Material changes

- Manaia Tee removal – high-cost forecasts have required the approach for this project to being reconsidered, and it was consequently deferred. Potential staged solutions and an updated timeframe are currently being developed.
- Kelvin Grove transformer upgrade – following further assessments of the potential load at risk and its value, this transformer upgrade has been deferred while other wider network plans are explored.

In addition to these changes, we also have several large customer projects in our planning pipeline for both load and distributed generation. These projects are still dependent on customer commitment and are therefore not listed above. We incorporate these large customer works into our long-term network development plans when there is a firm commitment from the customer.

4.2 Lifecycle asset management plans

There are no material changes to our lifecycle asset management plans. However, we continue to improve our fleet management practices in several areas such as in the areas listed below.

- We have developed a model of car versus pole impact risk, working closely with Waka Kotahi. This has helped us identify poles of high risk from vehicle impacts and we are now developing plans to mitigate these risks.
- We have reintroduced major maintenance on our oil ring main unit fleet, including testing and replacing the oil. This is giving us a much more accurate picture of the health of the fleet and is allowing us to make more informed decision around operating restriction to keep our field operators and the public safe.
- We are progressing the development of maintenance procedures, to provide more specific field guidance on undertaking our maintenance standards. This work is supporting an improvement in the accuracy of inspection results and defect information we collect from our maintenance contractors.

4.3 Asset management practices

There have been no material changes to the asset management practices and ongoing improvement plans that underpinned our previous AMP.

We have commissioned Copperleaf C55 and achieved provisional ISO55001 certification during FY21. Asset management improvements and investment efficiencies arising from these programmes will be reflected in future versions of our AMP.

4.4 Schedules 11a and 11b: Forecast operating and capital expenditure

4.4.1 Capex

In aggregate, total capital expenditure is similar to that in our 2021 AMP.

Changes to the Capex expenditure profile are largely attributed to the timing and costs of major and minor projects as discussed in earlier in this section, and updates required to reflect the increased demand forecast further out in the planning period.

Other changes arise from:

- Changes to Legislative and Regulatory expenditure due to a shift in the timing of forecasted expenditure requirements resulting from the Extended Reserve project for an automatic under-frequency load shedding (AUFLS) scheme in the North Island
- Increase in Asset Relocations forecast due to a change in the base year used for the base-step trend forecasting methodology
- Facilities Capex in Non-Network Capex has increased in FY22 and 23, reflecting the progression of office upgrade plans.

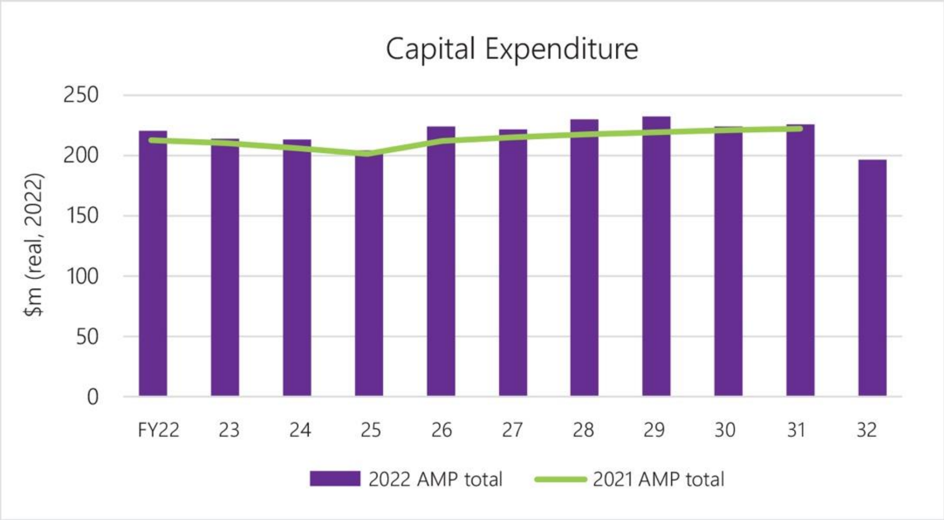
4. Material changes

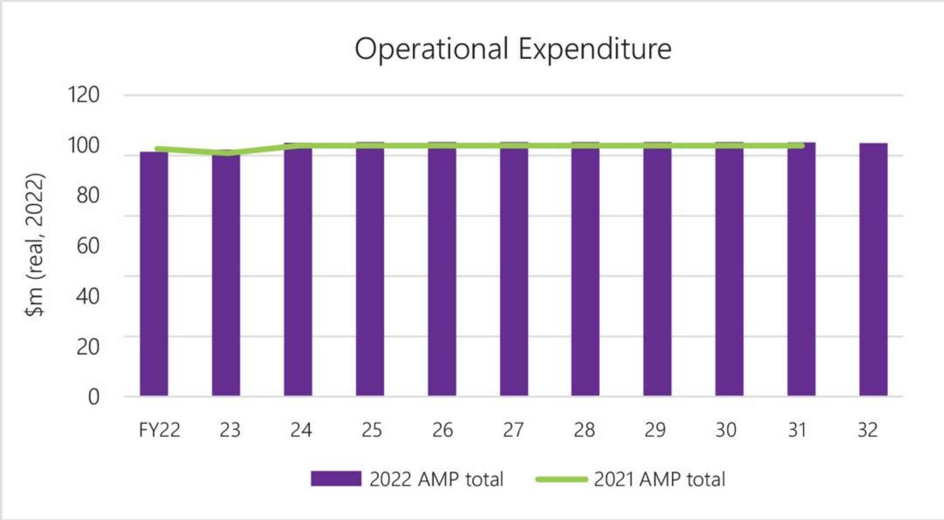
- Cost of financing and commissioned asset forecasts have changed as they are impacted by the material changes to Powerco's Network Development Plans

4.4.2 Opex

There has been some movement of forecast expenditure between maintenance categories, and between SONS and Business Support. These changes are not considered material, and overall, the total operational expenditure forecast remains consistent with that in our 2021 AMP.

Figure 4.1: AMP22 Capital and Operating Expenditure Forecasts





4.5 Schedule 12a: Asset condition

There have been no material changes to the approach for completing Schedule 12a since AMP21.

4.6 Schedule 12b: Forecast capacity

There have been no material changes to the approach for completing Schedule 12b since AMP21. Zone substation capacities have been updated to reflect completed network projects of the last 12 months.

Powerco is currently updating its electricity demand forecasting methodology, to better reflect the expected increase in electricity consumption from decarbonisation, electric vehicles and other electrification drivers (refer section 2.3). This updated demand forecast has been reflected Powerco's system-wide demand forecast shown in Schedule 12c and in the earlier sections of this AMP update but has not yet been reflected at a zone substation level. Therefore, this schedule's "Utilisation of Installed Firm Capacity + 5yrs %" relies on an older demand forecast methodology.

For Powerco's 2023 AMP we plan to rollout this updated demand forecasting methodology at a zone substation level, which will heavily inform our growth-based network planning.

4.7 Schedule 12c: Forecast network demand

There have been no material changes to the approach for completing Schedule 12c since AMP21, other than a revised approach to forecasting distributed generation connections, and the adoption of our scenario forecast model for peak demand.

4.8 Schedule 12d: Forecast interruptions and duration

There have been no material changes to the approach for completing Schedule 12d since AMP21. For the CPP period, the planned SAIDI/SAIFI forecasts remain within Powerco's planned quality limits.

In February 2022 the Powerco network was heavily impacted by Cyclone Dovi, which greatly impacted unplanned SAIDI and SAIFI performance for FY22. However this occurred after the Schedule 12d forecasts were compiled, and therefore the its impact is not reflected in the FY22 forecast.

5. Schedules

5. Schedules

5.1.1 Schedule 11A

												Company Name	Powerco
												AMP Planning Period	1 April 2022 – 31 March 2032

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).

This information is not part of audited disclosure information.

sch ref

7			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8		for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**
9	**11a(i): Expenditure on Assets Forecast**		**$000 (in nominal dollars)**										
10	Consumer connection		55,351	66,426	67,685	66,685	72,248	77,020	78,549	76,978	74,173	71,625	70,962
11	System growth		74,993	85,098	73,475	73,572	82,330	80,800	84,926	90,679	86,837	84,205	64,598
12	Asset replacement and renewal		94,238	80,726	88,743	88,612	99,067	96,446	102,779	105,986	110,976	121,905	116,581
13	Asset relocations		5,544	9,024	2,508	2,563	2,617	2,682	2,739	2,802	2,873	2,943	3,045
14	Reliability, safety and environment:												
15	Quality of supply		7,808	7,871	11,272	12,881	21,346	24,307	25,992	28,013	28,876	30,172	31,050
16	Legislative and regulatory		-	1,490	1,703	1,668	-	-	-	-	-	-	-
17	Other reliability, safety and environment		4,436	4,791	4,915	5,081	3,518	3,234	3,662	4,691	5,860	5,182	2,835
18	**Total reliability, safety and environment**		12,244	14,152	17,890	19,630	24,864	27,541	29,654	32,704	34,736	35,354	33,885
19	**Expenditure on network assets**		242,370	255,426	250,301	251,062	281,126	284,489	298,647	309,149	309,595	316,032	289,071
20	Expenditure on non-network assets		16,284	13,422	19,093	13,959	13,933	18,161	20,059	17,765	13,442	15,321	11,957
21	**Expenditure on assets**		258,654	268,848	269,394	265,021	295,059	302,650	318,706	326,914	323,037	331,353	301,028
22													
23	*plus* Cost of financing		2,078	2,078	2,078	2,078	2,078	2,078	2,078	2,078	2,078	2,078	2,078
24	*less* Value of capital contributions		39,110	48,004	45,398	44,836	48,505	51,492	52,562	51,579	49,672	48,018	47,092
25	*plus* Value of vested assets		-	-	-	-	-	-	-	-	-	-	-
26													
27	**Capital expenditure forecast**		221,622	222,922	226,074	222,263	248,632	253,236	268,222	277,413	275,443	285,413	256,014
28													
29	Assets commissioned		181,589	285,697	218,070	224,596	234,957	253,140	264,596	268,165	283,728	282,404	269,632

5. Schedules

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
31	for year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32
32		$000 (in constant prices)										
33	Consumer connection	55,351	64,800	64,783	62,334	66,103	68,944	68,799	65,980	62,218	58,798	56,997
34	System growth	74,993	82,626	70,156	68,436	74,863	71,584	73,304	76,301	71,293	67,314	50,372
35	Asset replacement and renewal	94,238	78,474	84,470	82,175	89,871	85,247	88,505	88,886	90,706	96,973	90,300
36	Asset relocations	5,544	8,777	2,385	2,379	2,375	2,377	2,371	2,368	2,371	2,371	2,396
37	Reliability, safety and environment:											
38	Quality of supply	7,808	7,631	10,689	11,919	19,276	21,385	22,273	23,380	23,481	23,907	23,968
39	Legislative and regulatory	-	1,437	1,601	1,531	-	-	-	-	-	-	-
40	Other reliability, safety and environment	4,436	4,669	4,665	4,723	3,189	2,858	3,162	3,935	4,813	4,123	2,190
41	**Total reliability, safety and environment**	12,244	13,737	16,955	18,173	22,465	24,243	25,435	27,315	28,294	28,030	26,158
42	**Expenditure on network assets**	242,370	248,414	238,749	233,497	255,677	252,395	258,414	260,850	254,882	253,486	226,223
43	Expenditure on non-network assets	16,284	13,087	18,262	13,063	12,768	16,308	17,653	15,325	11,369	12,704	9,721
44	**Expenditure on assets**	258,654	261,501	257,011	246,560	268,445	268,703	276,067	276,175	266,251	266,190	235,944
45												
46	**Subcomponents of expenditure on assets (where known)**											
47	Energy efficiency and demand side management, reduction of energy losses											
48	Overhead to underground conversion											
49	Research and development											
50												

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
52	for year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32
53	**Difference between nominal and constant price forecasts**	$000										
54	Consumer connection	-	1,626	2,902	4,351	6,145	8,076	9,750	10,998	11,955	12,827	13,965
55	System growth	-	2,472	3,319	5,136	7,467	9,216	11,622	14,378	15,544	16,891	14,226
56	Asset replacement and renewal	-	2,252	4,273	6,437	9,196	11,199	14,274	17,100	20,270	24,932	26,281
57	Asset relocations	-	247	123	184	242	305	368	434	502	572	649
58	Reliability, safety and environment:											
59	Quality of supply	-	240	583	962	2,070	2,922	3,719	4,633	5,395	6,265	7,082
60	Legislative and regulatory	-	53	102	137	-	-	-	-	-	-	-
61	Other reliability, safety and environment	-	122	250	358	329	376	500	756	1,047	1,059	645
62	**Total reliability, safety and environment**	-	415	935	1,457	2,399	3,298	4,219	5,389	6,442	7,324	7,727
63	**Expenditure on network assets**	-	7,012	11,552	17,565	25,449	32,094	40,233	48,299	54,713	62,546	62,848
64	Expenditure on non-network assets	-	335	831	896	1,165	1,853	2,406	2,440	2,073	2,617	2,236
65	**Expenditure on assets**	-	7,347	12,383	18,461	26,614	33,947	42,639	50,739	56,786	65,163	65,084

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27
11a(ii): Consumer Connection							
*Consumer types defined by EDB**		$000 (in constant prices)					
All Consumers		55,351	64,800	64,783	62,334	66,103	68,944
**include additional rows if needed*							
Consumer connection expenditure		55,351	64,800	64,783	62,334	66,103	68,944
less Capital contributions funding consumer connection		36,584	42,680	42,312	40,850	43,338	45,127
Consumer connection less capital contributions		18,767	22,120	22,471	21,484	22,765	23,817
11a(iii): System Growth							
Subtransmission		34,958	40,717	12,801	11,524	15,917	14,388
Zone substations		23,788	19,822	33,364	32,033	31,820	27,799
Distribution and LV lines		2,258	2,760	3,179	3,230	4,637	4,829
Distribution and LV cables		2,750	2,882	5,544	5,841	8,755	10,201
Distribution substations and transformers		1,983	613	2,200	1,749	1,072	849
Distribution switchgear		2,247	2,614	3,394	3,511	5,044	5,428
Other network assets		7,009	13,218	9,674	10,548	7,618	8,090
System growth expenditure		74,993	82,626	70,156	68,436	74,863	71,584
less Capital contributions funding system growth		-	-	-	-	-	-
System growth less capital contributions		74,993	82,626	70,156	68,436	74,863	71,584

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27
11a(iv): Asset Replacement and Renewal		$000 (in constant prices)					
Subtransmission		4,788	2,599	2,276	2,140	2,244	2,244
Zone substations		15,994	15,180	14,133	14,405	16,432	11,653
Distribution and LV lines		50,111	40,077	43,240	41,830	46,471	47,070
Distribution and LV cables		5,940	5,279	6,165	5,497	5,323	5,206
Distribution substations and transformers		7,870	6,975	7,828	7,607	8,617	8,653
Distribution switchgear		8,414	7,598	9,975	9,880	9,923	9,559
Other network assets		1,121	766	853	816	861	862
Asset replacement and renewal expenditure		94,238	78,474	84,470	82,175	89,871	85,247
less Capital contributions funding asset replacement and renewal		-	-	-	-	-	-
Asset replacement and renewal less capital contributions		94,238	78,474	84,470	82,175	89,871	85,247

Row			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
105			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
106		for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
107	**11a(v): Asset Relocations**							
108	*Project or programme**		**$000 (in constant prices)**					
109	Waka Kotahi undergrounding (SH2 TGA to Katikati)		4,380	7,636	-	-	-	-
110								
111								
112								
113								
114	**include additional rows if needed*							
115	All other project or programmes - asset relocations		1,164	1,141	2,385	2,379	2,375	2,377
116	**Asset relocations expenditure**		5,544	8,777	2,385	2,379	2,375	2,377
117	*less* Capital contributions funding asset relocations		2,526	4,124	1,111	1,111	1,111	1,111
118	**Asset relocations less capital contributions**		3,018	4,653	1,274	1,268	1,264	1,266
119								
120			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
121		for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
122	**11a(vi): Quality of Supply**							
123	*Project or programme**		**$000 (in constant prices)**					
124	Open-access networks - network visibility		1,670	1,629	1,918	2,870	7,641	7,647
125								
126								
127								
128								
129	**include additional rows if needed*							
130	All other projects or programmes - quality of supply		6,138	6,002	8,771	9,049	11,635	13,738
131	**Quality of supply expenditure**		7,808	7,631	10,689	11,919	19,276	21,385
132	*less* Capital contributions funding quality of supply		-	-	-	-	-	-
133	**Quality of supply less capital contributions**		7,808	7,631	10,689	11,919	19,276	21,385
134								
135			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
136		for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
137	**11a(vii): Legislative and Regulatory**							
138	*Project or programme**		**$000 (in constant prices)**					
139	Secondary systems (relay replacement for extended reserves)		-	1,437	1,601	1,531	-	-
140								
141								
142								
143								
144	**include additional rows if needed*							

All other projects or programmes - legislative and regulatory	-	-	-	-	-	-
Legislative and regulatory expenditure	-	1,437	1,601	1,531	-	-
less Capital contributions funding legislative and regulatory	-	-	-	-	-	-
Legislative and regulatory less capital contributions	-	1,437	1,601	1,531	-	-

11a(viii): Other Reliability, Safety and Environment

for year ended	*Current Year CY* **31 Mar 22**	*CY+1* **31 Mar 23**	*CY+2* **31 Mar 24**	*CY+3* **31 Mar 25**	*CY+4* **31 Mar 26**	*CY+5* **31 Mar 27**
*Project or programme**	**$000 (in constant prices)**					
**include additional rows if needed*						
All other projects or programmes - other reliability, safety and environment	4,436	4,669	4,665	4,723	3,189	2,858
Other reliability, safety and environment expenditure	4,436	4,669	4,665	4,723	3,189	2,858
less Capital contributions funding other reliability, safety and environment	-	-	-	-	-	-
Other reliability, safety and environment less capital contributions	4,436	4,669	4,665	4,723	3,189	2,858

11a(ix): Non-Network Assets

for year ended	*Current Year CY* **31 Mar 22**	*CY+1* **31 Mar 23**	*CY+2* **31 Mar 24**	*CY+3* **31 Mar 25**	*CY+4* **31 Mar 26**	*CY+5* **31 Mar 27**
Routine expenditure						
*Project or programme**	**$000 (in constant prices)**					
ICT capex	5,424	4,742	9,608	4,615	4,599	8,413
Facilities capex	1,832	963	254	254	1,480	845
Leases	2,810	1,268	1,268	1,268	1,268	1,268
**include additional rows if needed*						
All other projects or programmes - routine expenditure	-	-	-	-	-	-
Routine expenditure	10,066	6,973	11,130	6,137	7,347	10,526
Atypical expenditure						
*Project or programme**						
ICT capex	5,240	4,676	2,778	2,318	5,421	4,936
Facilities	978	1,438	4,354	4,608	-	846
**include additional rows if needed*						
All other projects or programmes - atypical expenditure	-	-	-	-	-	-
Atypical expenditure	6,218	6,114	7,132	6,926	5,421	5,782
Expenditure on non-network assets	16,284	13,087	18,262	13,063	12,768	16,308

5. Schedules

5.1.2 Schedule 11B

	Company Name	Powerco
	AMP Planning Period	1 April 2022 – 31 March 2032

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.
EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8	for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	7,241	7,273	8,400	8,660	8,924	9,159	9,401	9,648	9,904	10,166	10,359
11	Vegetation management	9,906	10,183	10,562	10,897	11,236	11,539	11,850	12,172	12,502	12,840	13,091
12	Routine and corrective maintenance and inspection	16,281	16,934	20,567	21,117	21,358	21,870	22,169	22,831	23,390	24,395	24,990
13	Asset replacement and renewal	10,589	10,328	12,823	13,205	12,775	13,080	13,391	13,712	14,040	14,377	14,612
14	**Network Opex**	44,017	44,718	52,352	53,879	54,293	55,648	56,811	58,363	59,836	61,778	63,052
15	System operations and network support	19,347	20,359	20,600	20,995	21,603	21,856	22,213	22,311	22,688	22,442	22,891
16	Business support	34,002	36,133	33,977	34,796	36,225	36,962	37,749	38,453	38,997	39,746	40,541
17	**Non-network opex**	53,349	56,492	54,577	55,791	57,828	58,818	59,962	60,764	61,685	62,188	63,432
18	**Operational expenditure**	97,366	101,210	106,929	109,670	112,121	114,466	116,773	119,127	121,521	123,966	126,484
19		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
20	for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	7,241	7,019	7,870	7,914	7,956	8,000	8,045	8,090	8,136	8,182	8,168
23	Vegetation management	9,906	9,827	9,896	9,957	10,017	10,079	10,141	10,206	10,270	10,334	10,322
24	Routine and corrective maintenance and inspection	16,281	16,286	19,166	19,166	18,902	18,965	18,836	19,007	19,080	19,498	19,572
25	Asset replacement and renewal	10,589	9,933	11,950	11,985	11,306	11,342	11,378	11,416	11,453	11,491	11,443
26	**Network Opex**	44,017	43,065	48,882	49,022	48,181	48,386	48,400	48,719	48,939	49,505	49,505
27	System operations and network support	19,347	19,850	19,704	19,648	19,796	19,626	19,549	19,247	19,189	18,609	18,609
28	Business support	34,002	35,230	32,499	32,564	33,195	33,190	33,221	33,173	32,982	32,957	32,957
29	**Non-network opex**	53,349	55,080	52,203	52,212	52,991	52,816	52,770	52,420	52,171	51,566	51,566
30	**Operational expenditure**	97,366	98,145	101,085	101,234	101,172	101,202	101,170	101,139	101,110	101,071	101,071
31	**Subcomponents of operational expenditure (where known)**											
32	Energy efficiency and demand side management, reduction of											
33	energy losses											
34	Direct billing*											
35	Research and Development											
36	Insurance											
37	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*											

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**
Difference between nominal and real forecasts	**$000**										
Service interruptions and emergencies	-	254	530	746	968	1,159	1,356	1,558	1,768	1,984	2,191
Vegetation management	-	356	666	940	1,219	1,460	1,709	1,966	2,232	2,506	2,769
Routine and corrective maintenance and inspection	-	648	1,401	1,951	2,456	2,905	3,333	3,824	4,310	4,897	5,418
Asset replacement and renewal	-	395	873	1,220	1,469	1,738	2,013	2,296	2,587	2,886	3,169
Network Opex	-	1,653	3,470	4,857	6,112	7,262	8,411	9,644	10,897	12,273	13,547
System operations and network support	-	509	896	1,347	1,807	2,230	2,664	3,064	3,499	3,833	4,282
Business support	-	903	1,478	2,232	3,030	3,772	4,528	5,280	6,015	6,789	7,584
Non-network opex	-	1,412	2,374	3,579	4,837	6,002	7,192	8,344	9,514	10,622	11,866
Operational expenditure	-	3,065	5,844	8,436	10,949	13,264	15,603	17,988	20,411	22,895	25,413

5. Schedules

5.1.3 Schedule 12A

Company Name	Powerco
AMP Planning Period	1 April 2022 – 31 March 2032

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref

7					Asset condition at start of planning period (percentage of units by grade)							
8												
9	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
10	All	Overhead Line	Concrete poles / steel structure	No.	0.48%	0.99%	3.76%	6.10%	88.67%	-	4	2.60%
11	All	Overhead Line	Wood poles	No.	6.21%	11.05%	30.05%	26.86%	25.84%	-	4	22.59%
12	All	Overhead Line	Other pole types	No.	-	-	-	-	39.75%	60.25%	3	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	0.34%	2.24%	12.95%	72.25%	12.21%	-	4	4.60%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	-	-	N/A	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	0.12%	0.70%	10.11%	3.27%	85.80%	-	4	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	22.09%	33.29%	44.54%	0.08%	-	4	-
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	-	-	-	-	N/A	-
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	-	14.47%	85.53%	-	4	-
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	-	-	-	N/A	-
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	-	-	-	N/A	-
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	-	-	-	N/A	-
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	-	-	-	N/A	-
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	-	-	-	N/A	-
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	6.94%	35.42%	18.06%	29.86%	6.25%	3.47%	3	15.28%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	-	-	N/A	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	1.90%	98.10%	-	4	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	0.59%	15.38%	23.67%	60.36%	-	4	20.71%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	91.30%	8.70%	2	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	26.61%	1.50%	16.47%	14.75%	40.67%	-	4	8.00%
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	100.00%	-	-	4	-
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	-	-	N/A	-
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	21.05%	10.53%	68.42%	-	4	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	-	16.88%	16.88%	66.23%	-	4	22.00%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	3.92%	7.84%	88.24%	-	4	-
35												

36					Asset condition at start of planning period (percentage of units by grade)							
37												
38	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	2.14%	8.02%	16.04%	36.90%	36.90%	-	4	8.56%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	0.12%	10.66%	25.70%	53.81%	9.70%	-	3	7.20%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	-	N/A	-
42	HV	Distribution Line	SWER conductor	km	-	3.44%	28.95%	58.67%	8.93%	-	3	-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	1.41%	1.33%	9.81%	19.71%	67.73%	-	3	1.86%
44	HV	Distribution Cable	Distribution UG PILC	km	0.06%	-	0.58%	15.81%	83.55%	-	3	1.04%
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	-	100.00%	-	3	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	0.16%	2.69%	0.63%	0.47%	96.04%	-	4	2.69%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	7.44%	36.28%	9.77%	10.70%	35.81%	-	4	57.70%
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	3.88%	2.95%	11.23%	17.68%	64.27%	-	3	6.97%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	17.53%	2.31%	8.25%	12.18%	59.73%	-	4	2.40%
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	1.23%	2.25%	8.50%	18.57%	69.44%	-	4	7.13%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	3.08%	1.94%	7.32%	11.67%	76.00%	-	3	5.24%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	1.46%	2.87%	11.70%	23.38%	60.59%	-	4	4.40%
53	HV	Distribution Transformer	Voltage regulators	No.	0.35%	-	-	0.71%	98.94%	-	4	0.69%
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	1.27%	1.34%	5.32%	9.11%	82.95%	-	3	2.21%
55	LV	LV Line	LV OH Conductor	km	0.06%	13.42%	18.64%	54.43%	13.45%	-	2	6.71%
56	LV	LV Cable	LV UG Cable	km	0.73%	0.90%	7.87%	25.11%	65.39%	-	2	-
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	1.95%	2.21%	15.66%	19.57%	60.60%	-	2	-
58	LV	Connections	OH/UG consumer service connections	No.	4.40%	2.32%	24.88%	26.02%	42.38%	-	1	-
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	15.73%	4.53%	5.34%	16.39%	58.02%	-	3	23.28%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	42.49%	26.84%	28.12%	2.56%	-	2	25.56%
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	2.08%	64.58%	33.33%	-	4	-
62	All	Load Control	Centralised plant	Lot	-	27.78%	-	13.89%	58.33%	-	4	-
63	All	Load Control	Relays	No.	10.71%	19.87%	1.61%	6.00%	61.81%	-	1	3.97%
64	All	Civils	Cable Tunnels	km	-	-	-	-	-	-	N/A	-

5. Schedules

5.1.4 Schedule 12B

		Company Name	Powerco
		AMP Planning Period	1 April 2022 – 31 March 2032

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule

sch ref

7 **12b(i): System Growth - Zone Substations**

sch ref	*Existing Zone Substations*	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
8										
9	Coromandel	4	1	N-1	1	430%	6	77%	No constraint within +5 years	Single 66kV circuit. Proposed backup distributed generation project.
10	Kerepehi	10	-	N	2	-	5	244%	Subtransmission Circuit & Transforr	Single 66kV circuit. Some increase in 11kV backfeed capacity in the short term with routine projects.
11	Matatoki	4	-	N	2	-	9	57%	No constraint within +5 years	Single Tx. 2nd transformer proposed 2023/24.
12	Tairua	9	8	N	-	119%	8	127%	Transformer	Tx firm capacity constraint remains due to Whenuakite substation being deferred
13	Thames T1 & T2	12	-	N-1	2	-	19	64%	No constraint within +5 years	66kV new Kopu-Kauaeranga line removes binding constraint
14	Thames T3	2	7	N-1 SW	7	25%	7	26%	No constraint within +5 years	Customer agreed security. No load increase indicated.
15	Whitianga	15	-	N	-	-	16	99%	No constraint within +5 years	Whenuakite project deferral results in Tx firm capacity constraint in the future
16	Paeroa	7	6	N	2	124%	10	82%	No constraint within +5 years	Transformer feeder arrangement restricts firm capacity to transformer capacity. Risk managed operationally in the interim.
17	Waihi	17	21	N-1	1	81%	21	83%	No constraint within +5 years	Customer agreed security.
18	Waihi Beach	5	3	N	3	155%	3	185%	Subtransmission circuit	Single 33kV cct. 2nd Transformer planned 2023 commissioning. Proposed backup distributed generation post-2023. Removal of tee near Waihi to improve reliability.
19	Whangamata	9	5	N	1	176%	5	218%	Subtransmission circuit	Battery & Generator recently commissioned. 11kV link to Tairua for backup.
20	Aongatete	4	5	N-1	2	72%	5	96%	No constraint within +5 years	Planned renewal of Aongatete substation
21	Bethlehem	11	8	N	8	136%	24	49%	No constraint within +5 years	Single transformer Substation - 2nd Tx planned 2023-2025 to address N-1 Tx constraint.
22	Hamilton St	11	21	N-1	12	49%	21	79%	No constraint within +5 years	Recently commissioned Sulphur Point substation offloaded Hamilton Street substation.
23	Katikati	11	11	N-1 SW	5	93%	11	100%	No constraint within +5 years	Second transformer and second circuit completed.
24	Kauri Pt	3	2	N-1	2	181%	2	188%	Subtransmission Circuit	Single Tx and subtransmission circuit. Removal of the tee at Katikati to improve reliability
25	Matua	9	7	N-1	8	119%	7	124%	Transformer and Subtransmission c	Single Tx limits security. Second transformer planned 2026-2028.
26	Omokoroa	12	13	N-1 SW	3	90%	13	97%	No constraint within +5 years	Both transformers approaching firm load. New third 33kV circuit planned for 2021-2023. Pahoia substation proposed to offload Omokoroa substation
27	Otumoetai	14	14	N-1 SW	11	106%	14	123%	Transformer	Minor constraint - managed operationally. Bethlehem second transformer project will offload Otumoetai and reduce its MD

28		Pyes Pa	14	24	N-1	8	59%	24	68%	No constraint within +5 years	Possible constraint depending on the rate of commercial/industrial growth. New Belk Road substation planned 2022-2027 to offload Pyes Pa.
29		Waihi Rd	20	24	N-1	10	84%	24	95%	No constraint within +5 years	
30		Welcome Bay	23	21	N	4	107%	21	125%	Transformer and Subtransmission c	Managed operationally. New Oropi substation planned 2024-2027 will relieve constraints at Welcome Bay.
31		Matapihi	13	24	N-1	14	53%	24	56%	No constraint within +5 years	
32		Omanu	12	24	N-1	12	51%	24	53%	No constraint within +5 years	
33		Papamoa	17	21	N-1	10	78%	21	84%	No constraint within +5 years	11kV offload with new feeders from Wairakei substation
34		Te Maunga	10	10	N-1 SW	10	98%	10	108%	Transformer	Te Maunga 2nd transformer lifts N-1 Tx capacity
35		Triton	18	21	N-1	10	84%	24	85%	No constraint within +5 years	Transformers upgraded and load shift to Omanu
36		Wairakei	9	24	N-1	6	35%	24	44%	No constraint within +5 years	
37		Atuaroa Ave	9	-	N	7	-	-	-	Subtransmission Circuit and Transfo	33kV second circuit 2026 and 2nd transformer 2025
38		Paengaroa	6	4	N-1 SW	4	161%	12	51%	No constraint within +5 years	Second transformer 2024 and second circuit 2028 proposed for the future
39		Pongakawa	5	1	N-1	1	346%	4	129%	Subtransmission Circuit	Single circuit limited 11kV backfeed. Potential for future generation or non-network support to provide backup.
40		Te Puke	20	23	N-1	11	88%	23	95%	No constraint within +5 years	
41		Farmer Rd	6	-	N-1 SW	1	-	-	-	Subtransmission circuit & transform	Customer's planned load growth will exceed existing transfomer capacity and overload existing 33kV subtranmission circuit.
42		Inghams	4	-	N	-	-	-	-	Subtransmission Circuit & Transforr	Customer agreed security
43		Mikkelsen Rd	13	19	N-1	4	65%	19	68%	No constraint within +5 years	
44		Morrinsville	8	-	N-1	2	-	8	124%	Transformer	2nd 33kV circuit ~2023. Future Sub upgrade post 2023.
45		Piako	13	15	N-1	7	84%	15	89%	No constraint within +5 years	
46		Tahuna	5	1	N-1	1	771%	2	433%	Subtransmission Circuit	Single 33kV circuit. Risk mitigated operationally via 11kV backfeeds
47		Tatua	5	-	N	-	-	-	-	Subtransmission Circuit and Transfo	Customer's load growth will exceed the exisiting transformer capacity and overload 33kV subtransmission circuit. Grid reconfiguration might demand increased transfer capacity to support backfeed.
48		Waitoa	12	19	N-1	-	64%	19	70%	No constraint within +5 years	
49		Walton	5	-	N	2	-	-	-	Transformer	Single Transformer. Risk managed operationally
50		Browne St	9	11	N-1 SW	7	89%	11	104%	Transformer	Very minor, low risk. Managed operationally
51		Lake Rd	6	2	N	2	365%	5	150%	Transformer	2nd transformer commissioning.
52		Tirau	8	-	N	-	-	10	103%	Transformer	Single transformer. Customer driven 2nd Tx proposed for early 2022.
53		Putaruru	12	-	N	1	-	17	72%	No constraint within +5 years	New GXP, Subtrans. & transf upgrades .
54		Tower Rd	8	17	N-1	5	49%	17	52%	No constraint within +5 years	GXP and Subtrans upgraded, & 2nd Tx added.
55		Waharoa Nth	3	3	N	-	128%	9	44%	No constraint within +5 years	Transformer planned renewal will alleviate constraint.
56		Waharoa Sth	5	-	N	-	-	9	61%	No constraint within +5 years	Transformer planned renewal will alleviate constraint.
57		Baird Rd	10	-	N-1	7	-	11	99%	No constraint within +5 years	Baird Rd & Maraetai Rd operating as 33kV closed loop.
58		Midway / Lakeside	4	-	N	-	-	-	-	Subtransmission Circuit & Transforr	Customer agreed security at both substations
59		Maraetai Rd	8	-	N-1	7	-	15	57%	No constraint within +5 years	Baird Rd & Maraetai Rd operating as 33kV closed loop.
60		Bell Block	14	25	N-1	9	58%	25	70%	No constraint within +5 years	Load transfer planned post 2024
61		Brooklands	17	24	N-1	7	73%	24	75%	No constraint within +5 years	
62		Cardiff	2	3	N-1 SW	3	68%	3	76%	No constraint within +5 years	
63		City	14	20	N-1	12	72%	20	90%	No constraint within +5 years	Capacity upgrade planned post 2027
64		Cloton Rd	9	13	N-1	1	69%	13	81%	No constraint within +5 years	
65		Douglas	1	2	N-1 SW	2	76%	2	82%	No constraint within +5 years	Single circuit. Very low risk. Most load can be backfed.
66		Eltham	10	11	N-1 SW	3	88%	15	69%	No constraint within +5 years	Transformer upgrade ~2022

5. Schedules

67		Inglewood	5	6	N-1 SW	3	85%	6	90%	No constraint within +5 years	Load transfer planned post 2025
68		Kaponga	3	3	N-1 SW	2	103%	3	110%	Transformer	Low risk of failure. Operationally managed.
69		Katere	15	24	N-1	11	60%	24	63%	No constraint within +5 years	
70		McKee	1	-	N	-	-	-	-	Transformer	
71		Motukawa	1	1	N-1 SW	1	77%	1	77%	No constraint within +5 years	Single transformer. Most load can be backfed.
72		Moturoa	18	24	N-1	7	77%	30	64%	No constraint within +5 years	New 33kV circuits and transformers 2019/20
73		Oakura	4	-	N	-	-	-	-	Subtransmission circuit	Single cct & Tx. 11kV backfed adequate till 2nd cct ~2025
74		Waihapa	1	2	N-1 SW	2	21%	2	42%	No constraint within +5 years	
75		Waitara East	5	6	N-1	4	80%	6	85%	No constraint within +5 years	
76		Waitara West	6	6	N-1 SW	8	100%	10	70%	No constraint within +5 years	Transformer upgrade planned resuing Pohokura units
77		Cambria	14	17	N-1	5	80%	17	84%	No constraint within +5 years	Transformer & Subtrans upgrade planned ~2026
78		Kapuni	5	11	N-1	4	50%	11	51%	No constraint within +5 years	
79		Livingstone	3	3	N-1 SW	1	83%	5	54%	No constraint within +5 years	Transformers scheduled for replacement ~2025 (higher cap)
80		Manaia	6	5	N	5	117%	5	121%	Transformer	Single Tx bank (after renewal)
81		Ngariki	3	4	N-1 SW	4	67%	4	103%	Transformer	
82		Pungarehu	3	5	N-1	2	71%	5	76%	No constraint within +5 years	Low risk - operationally managed (e.g. backfeeds)
83		Tasman	7	6	N-1 SW	3	110%	6	113%	Transformer	Low risk - operationally managed (e.g. backfeeds)
84		Mokoia	3	3	N-1 SW	4	100%	3	106%	Transformer	New Sub. Replaces Whareroa.
85		Beach Rd	10	16	N-1	3	64%	16	66%	No constraint within +5 years	Subtrans upgrades complete pre 2025.
86		Blink Bonnie	3	3	N-1 SW	3	93%	3	120%	Transformer	Low risk of failure. Security upgrades planned post 2026
87		Castlecliff	9	9	N-1 SW	5	101%	13	72%	No constraint within +5 years	Post 2024 plan to upgrade transformers
88		Hatricks Wharf	10	-	N	6	-	10	131%	Transformer	Single transf, but 11kV bus tie (Taupo Quay) mitigates risk
89		Kai Iwi	2	1	N	1	204%	1	245%	Subtransmission Circuit	Single 33kV cct & single Tx. Also N security GXP.
90		Peat St	14	-	N-1	6	-	-	-	Transpower	2nd 33kV circuit ~2023, but N secure GXP limits security
91		Roberts Ave	4	6	N-1 SW	6	74%	6	76%	No constraint within +5 years	2nd 33kV circuit ~2023, but N secure GXP limits security
92		Taupo Quay	6	-	N-1 SW	8	-	10	100%	Transformer	2nd 33kV circuit planned 2023. Single Tx with bus tie limits security.
93		Wanganui East	5	3	N	3	159%	3	162%	Subtransmission Circuit	Single 33kV cct and Tx. Post 2025 plan for 2nd cct and Tx.
94		Taihape	4	1	N	1	538%	1	563%	Transformer	Single transformer. 2nd Transformer post 2026
95		Waiouru	2	1	N	1	480%	1	480%	Subtransmission circuit	N secure GXP, 33kV & Tx. Post 2026 11kV upgrade.
96		Arahina	8	3	N	3	248%	3	252%	Subtransmission Circuit	N secure GXP, 33kV & Tx. Post 2026 2nd cct & Tx.
97		Bulls	5	2	N	2	255%	2	305%	Transformer	~2023 2nd 33kV. Post 2024 2nd transformer.
98		Pukepapa	4	2	N	2	184%	2	316%	Transformer	Single transformer. Limited backfeed. Post 2026 - 2nd Tx
99		Rata	2	1	N	1	314%	1	443%	Subtransmission circuit	Single 33kV cct and Tx. Post 2028 plan for 11kV Upgrade.
100		Feilding	22	24	N-1 SW	2	93%	24	97%	No constraint within +5 years	Re-rate transformers 2023 and post 2023 33kV upgrade and new zone substation
101		Ferguson St	10	24	N-1	15	44%	24	48%	No constraint within +5 years	New Sub: 2019. 2021: 2nd Tx added & full N-1 33kV capacity.
102		Kairanga	18	19	N-1 SW	8	92%	24	77%	No constraint within +5 years	Transformers upgrade planned ~2023
103		Keith St	18	22	N-1	-	82%	22	87%	No constraint within +5 years	Upgrades offload 33kV circuits feeding Main and Keith St
104		Kelvin Grove	16	17	N-1 SW	5	91%	24	76%	No constraint within +5 years	Potential new NEI substation post 2023.
105		Kimbolton	3	1	N	1	193%	1	200%	Subtransmission Circuit	Single 33kV circuit & single transformer. Remote Sub.
106		Main St	15	17	N-1	13	86%	25	92%	No constraint within +5 years	New Fergusson sub & 33kV cables address ex. high risk constraints.
107		Milson	16	18	N-1 SW	5	91%	19	93%	No constraint within +5 years	Posible TX and subtransmission upgrade post 2023
108		Pascal St	14	17	N-1	12	80%	25	76%	No constraint within +5 years	New Fergusson sub & 33kV cables address ex. high risk constraints.
109		Sanson	9	-	N-1 SW	4	-	11	87%	No constraint within +5 years	33kV backfeed secures load. New Sanson-Bulls 33kV link and new Ohakea Sub
110		Turitea	14	-	N-1	5	-	-	-	Subtransmission Circuit	Switched 33kV security - Second 33kV circuit and TX upgrade post 2023

111	Alfredton	1	1	N	0	36%	1	43%	No constraint within +5 years	Single Transf. but adequate backfeed.
112	Mangamutu	12	13	N-1	1	93%	13	105%	Transformer	Major customer largely determines security requirements.
113	Parkville	2	-	N	-	-	-	-	Transformer	Single transformer
114	Pongaroa	1	3	N	1	24%	3	31%	No constraint within +5 years	Single transformer, but adequate backfeed
115	Akura	12	9	N-1 SW	7	129%	15	94%	No constraint within +5 years	Txs replaced & section of 33kV circuit upgraded, ~2022
116	Awatoitoi	1	3	N	1	27%	3	47%	No constraint within +5 years	
117	Chapel	13	14	N-1	5	97%	23	60%	No constraint within +5 years	Upgrade short section of 33kV cable pre 2022.
118	Clareville	10	9	N	1	102%	9	111%	Transformer	Transformer and 33kV upgrade post 2024
119	Featherston	4	0	N	0	4,300%	0	4,700%	Transformer	Single transformer. 2nd bank proposed in longer term, 2025 new sub to increase transfer capacity
120	Gladstone	1	1	N	0	71%	1	86%	No constraint within +5 years	
121	Hau Nui	1	-	N	-	-	-	-	Subtransmission Circuit & Transfor	Generation site. Not economic to provide higher security
122	Kempton	5	0	N	0	1,275%	0	1,350%	Subtransmission Circuit	Post 2024: 2nd 33kV supply & upgraded 2nd transformer, 2025 new sub to increase transfer capacity
123	Martinborough	4	0	N	0	4,000%	0	4,800%	Transformer	Single transformer. 2nd Tx planned post 2024, 2025 new sub to increase transfer capacity
124	Norfolk	6	11	N-1	4	58%	11	63%	No constraint within +5 years	Risk is very low. Post 2024 upgrade planned.
125	Te Ore Ore	7	7	N	7	107%	7	113%	Transformer	Single transformer
126	Tinui	1	1	N	1	54%	1	92%	No constraint within +5 years	
127	Tuhitarata	3	-	N	-	-	1	450%	Subtransmission circuit	Single 33kV circuit & single transformer, 2025 New Sub to increase transfer capacity

[1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

5. Schedules

5.1.5 Schedule 12C

Company Name	Powerco
AMP Planning Period	1 April 2022 – 31 March 2032

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref							
7	**12c(i): Consumer Connections**						
8	*Number of ICPs connected in year by consumer type*			**Number of connections**			
9		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10	for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
11	*Consumer types defined by EDB**						
12	Residential/Small Commercial	5,278	4,978	4,978	4,978	4,978	4,978
13	Commercial	54	53	53	53	53	53
14	Large Commercial/Industrial	18	18	18	18	18	18
15							
16							
17	**Connections total**	5,350	5,049	5,049	5,049	5,049	5,049
18	**include additional rows if needed*						
19	**Distributed generation**						
20	Number of connections	1,140	1,465	1,628	2,117	2,442	2,931
21	Capacity of distributed generation installed in year (MVA)	10	13	14	18	21	25
22	**12c(ii) System Demand**						
23		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
24	**Maximum coincident system demand (MW)** — for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
25	GXP demand	861	870	884	900	919	941
26	*plus* Distributed generation output at HV and above	125	127	129	131	134	137
27	**Maximum coincident system demand**	986	997	1,013	1,031	1,053	1,078
28	*less* Net transfers to (from) other EDBs at HV and above						
29	**Demand on system for supply to consumers' connection points**	986	997	1,013	1,031	1,053	1,078

30		**Electricity volumes carried (GWh)**						
31		Electricity supplied from GXPs	4,579	4,630	4,704	4,788	4,890	5,006
32	*less*	Electricity exports to GXPs	166	168	171	174	177	181
33	*plus*	Electricity supplied from distributed generation	821	830	843	858	877	898
34	*less*	Net electricity supplied to (from) other EDBs	-	-	-	-	-	-
35		**Electricity entering system for supply to ICPs**	5,234	5,292	5,377	5,473	5,590	5,722
36	*less*	Total energy delivered to ICPs	4,962	5,017	5,098	5,188	5,299	5,425
37		**Losses**	272	275	280	285	291	298
38								
39		**Load factor**	61%	61%	61%	61%	61%	61%
40		**Loss ratio**	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%

5. Schedules

5.1.6 Schedule 12D

Company Name	Powerco
AMP Planning Period	1 April 2022 – 31 March 2032
Network / Sub-network Name	Powerco - combined

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
8								
9		for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
10	**SAIDI**							
11	Class B (planned interruptions on the network)		98.2	99.3	94.1	90.2	91.3	90.0
12	Class C (unplanned interruptions on the network)		207.9	197.4	195.0	195.4	197.3	198.5
13	**SAIFI**							
14	Class B (planned interruptions on the network)		0.41	0.39	0.42	0.41	0.41	0.40
15	Class C (unplanned interruptions on the network)		1.98	2.27	2.25	2.26	2.28	2.31

5. Schedules

Company Name	Powerco
AMP Planning Period	1 April 2022 – 31 March 2032
Network / Sub-network Name	Powerco - Eastern Region

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
9	for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	98.2	99.3	94.1	90.2	91.3	90.0
12	Class C (unplanned interruptions on the network)	207.9	197.4	195.0	195.4	197.3	198.5
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.41	0.39	0.42	0.41	0.41	0.40
15	Class C (unplanned interruptions on the network)	1.98	2.27	2.25	2.26	2.28	2.31

Company Name	Powerco
AMP Planning Period	1 April 2022 – 31 March 2032
Network / Sub-network Name	Powerco - Western Region

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
9	for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	98.2	99.3	94.1	90.2	91.3	90.0
12	Class C (unplanned interruptions on the network)	207.9	197.4	195.0	195.4	197.3	198.5
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.41	0.39	0.42	0.41	0.41	0.40
15	Class C (unplanned interruptions on the network)	1.98	2.27	2.25	2.26	2.28	2.31

5. Schedules

5.1.7 Schedule 14A

Company Name	**Powerco**
For Year Ended	**31 March 2022**

Schedule 14a **Mandatory explanatory notes on forecast information**

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.

2. This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11a)

3. In the box below, comment on the difference between nominal and constant price capital expenditure for the current disclosure year and 10 year planning period, as disclosed in Schedule 11a.

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts

Our approach involves applying different cost escalators to our constant price expenditure forecasts. Our escalators have been developed using:

- Independent forecasts of input price indices that reflect the various costs that we face, including material and labour components.
- Weighting factors for asset types, such as transformers, that are made up of a range of inputs.

We have used the above inputs to develop tailored cost escalators for our cost categories. These are then applied to our constant price capital expenditure forecasts to produce the forecasts in nominal dollars for Schedule 11a.

Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b)

4. In the box below, comment on the difference between nominal and constant price operational expenditure for the current disclosure year and 10 year planning period, as disclosed in Schedule 11b.

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts

Our approach involves applying different cost escalators to our constant price expenditure forecasts. Our escalators have been developed using:

- Independent forecasts of Producers Price Index (PPI), Labour Cost Index (LCI) and Consumer Price Index (CPI).
- Weighting factors for opex cost categories.

We have used the above inputs to develop tailored cost escalators for our cost categories. These are then applied to our constant price operating expenditure forecasts to produce the forecasts in nominal dollars for Schedule 11b.
We have used the NZIER December 2021 PPI and CPI forecasts up to March 2026 with assumed long-term rates of 2%, and the NZIER LCI forecast up to March 2025 with an assumed long-term rate of 2.1%.

6. Certificate for Year-Beginning Disclosures

6. Certificate for Year-Beginning Disclosures

Pursuant to clause 2.9.1 of Section 2.9

We, John Loughlin and Paul Callow being directors of Powerco Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a) The following attached information of Powerco Limited prepared for the purposes of clauses 2.6.1, 2.6.6, and 2.7.2 of the Electricity Information Disclosure Determination 2012 in all material respects complies with that determination.

b) The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

c) The forecasts in Schedules 11a, 11b, 12a, 12b, 12c and 12d are based on objective and reasonable assumptions which with align with Powerco's corporate vision and strategy and are documented in retained records.

Director

Director