Electra

Electricity Pricing Methodology

Pursuant to the Electricity Distribution Information Disclosure Determination 2012, clause 2.4.1 and the Electricity Authority Distribution Pricing Principles

Effective from 1 April 2024 to 31 March 2025

PURPOSE STATEMENT

This Pricing Methodology describes the approach we use to set our electricity distribution prices that apply from 1 April 2024 to 31 March 2025. The revenue we earn from these charges enables us to build, operate and maintain an electricity network to serve consumers in the Horowhenua and Kāpiti Coast region safely and reliably.

We publish our pricing methodology before the start of each disclosure year (i.e., 1 April), as prescribed by section 2.4—Pricing and Related Information of the *Electricity Distribution Information Disclosure 2012* (the ID Determination).

PRICE EFFICIENCY ALONGSIDE AFFORDABILITY

The overall objective of our pricing is to signal the efficient use of our electricity distribution network (the network) to facilitate the provision of least-cost electricity distribution services for the long-term benefit of consumers. Our prices signal the efficient use of our existing network and reflect the costs of future investment needed on our network to support changes in consumer behaviour. Efficient pricing has an important role to play as New Zealand's energy needs become more dependent on electricity, and we shift away from fossil fuels to being carbon-zero by 2050, avoiding—

> *'… over-investment by the consumer in technologies to avoid network charges, shifting costs onto other consumers; and unnecessary network investments.'*[1]

Playing our role in New Zealand's decarbonised future requires us to invest heavily in our network. We must ensure that electricity can be delivered when and where our community needs it. At the same time, as we make these investments, we must consider the impact those investments will have on our connected consumers and keep affordability at the forefront of our transition.

As New Zealand moves away from fossil fuels as a source of energy, our community will use more electricity to run cars, heat homes, and operate businesses. Our community must have a supply of electricity that is affordable and supports the transition through accessibility and reasonable prices.

To support the use of electricity and the transition to a decarbonised economy, we have set our prices to encourage consumers to shift consumption into the off-peak periods on our network. By making small changes to their daily activities, consumers can shift consumption into the off-peak periods when the costs are lower and more affordable.

These small changes can be made by replacing incandescent lightbulbs with LED when the incandescent bulb stops working, putting the washer, dryer, or dishwasher on a timer to start after 11 pm, and when replacing appliances considering the energy efficiency of the new appliance, the more stars, the less energy they use.

SHOP AROUND FOR THE RIGHT ELECTRICITY RETAILER

We are one link in the supply chain and do not have a direct relationship with our connected consumers. This relationship lies with the electricity retailers. Consumers can choose their electricity retailer. There are numerous electricity retailer offerings in the market, and the right one for every

1 Electricity Authority, More efficient distribution network pricing – principles and practice, Decision paper, 4 June 2019 (the Decisions Paper), Executive summary at page ii.

consumer. Powerswitch is a free service that helps consumers to find the right offering for them. We encourage consumers to use this free service and be sure their chosen retailer is the right fit.

WE ARE OWNED BY THE COMMUNITY WE SERVE

The Electra Trust holds the shares in Electra on behalf of all connected consumers on the Network. The Trust represents consumers' interests as we progress through our transitional pricing journey. We remain committed to listening to consumers and ensuring we continue to meet their expectations on service levels and price.

PRICING METHODOLOGY OVERVIEW

To demonstrate compliance with the ID Determination and the realisation of our goal, we have structured our Pricing methodology to include the following:

- a description of the methodology we used to calculate our network prices, including:
    - the details of the Revenue Requirement to be recovered from consumers over the pricing year
    - the Target Revenue to be collected from each consumer group
    - an outline of how we have determined our consumer pricing groups
    - an outline of how we assign consumers to our consumer groups
    - how costs and revenues are allocated to each price category
    - discussion of consistency (or otherwise) with the Electricity Authority's Pricing Principles
- an explanation of the longer-term pricing strategy (5 years) and any expected significant changes
- a description of our approach to non-standard contracts and pricing relating to distributed generation
- disclosure of our capital contribution policy.

Our pricing methodology uses standard industry terminology throughout. To help consumers understand our pricing methodology, we have provided a glossary at the end of this document.

WHERE TO GET A COPY OF THIS PRICING METHODOLOGY

This Pricing Methodology can be downloaded from our website, or call us at 0800 Electra (0800 353 2872), and we will email or post a copy. On weekdays, you can also drop into our offices on the corner of Bristol & Exeter Streets, Levin, between 8 am and 5 pm.

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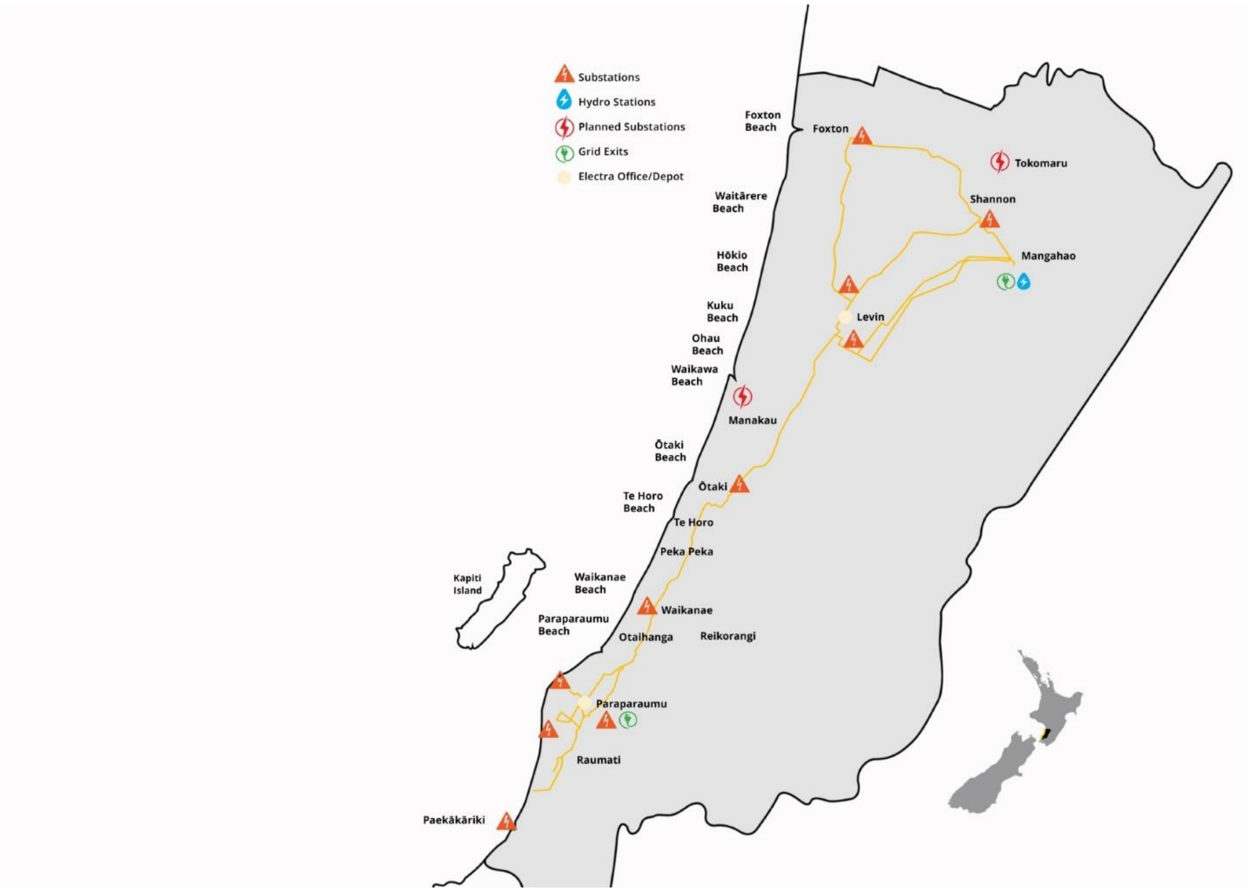
Introduction

1.1 WHO IS ELECTRA LIMITED?

Electra Limited (Electra) owns and operates the electricity distribution network across the Horowhenua and Kāpiti districts shown in Figure 1 on the land between the Tasman Sea and Tararua Rangers, stretching from Foxton and Tokomaru in the north to Paekākāriki in the south.

Figure 1: A map of our supply area

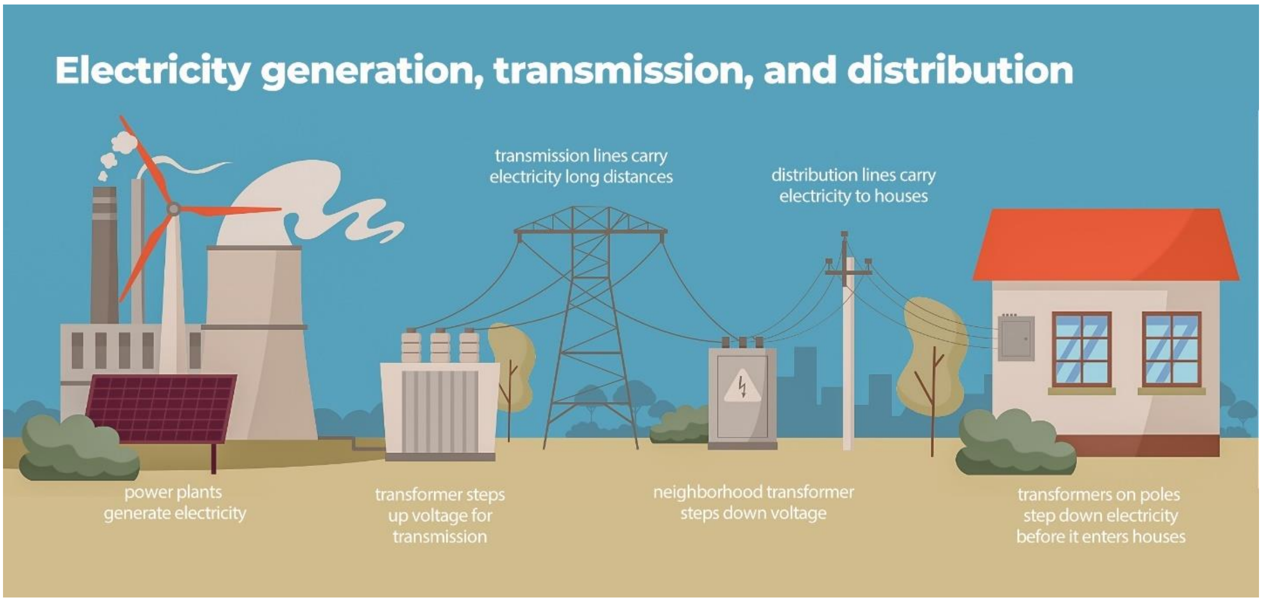


The network covers an area of approximately 1,628 km square with a mix of overhead infrastructure to urban and rural networks consisting of 21,609 poles, 2,380 km of cables and overhead lines, and 2,655 transformers.

We are supplied by two grid exit points from the Transpower national grid at Valley Road, Paraparaumu, in the south and Mangahao in the north.

Electra is wholly owned by its 46,333 consumers, with shares in the company held on behalf of all consumers by the Electra Trust, whose Trustees represent the owners' interests and protect their assets. Figure 2 shows the role we play in the New Zealand electricity market.

Figure 2: Electricity Supply Chain Infographic



1.2 OUR CONSUMERS ARE OUR BENEFICIARIES

The Electra Trust holds the shares on behalf of all connected consumers on the network. The trustees are elected to represent all connected consumers' interests and drive the company's direction via an annual letter of expectations and a Statement of Corporate Intent.

Every year, we share the benefits of local ownership by applying a posted discount to our consumers. The discount reflects the nature of our community ownership and drives our commitment to managing our network efficiently for the long-term benefit of consumers.

1.3 ELECTRICITY DISTRIBUTION SERVICES ARE REGULATED

Electricity distribution services are a natural monopoly. As such, we are subject to various regulatory requirements that the Commerce Commission (the Commission) and the Electricity Authority (the Authority) administer. The Commission administers economic regulation under Part 4 of the *Commerce Act 1986* (the Act). The Authority regulates the New Zealand electricity market under the *Electricity Industry Participation Code* 2010 (the Code).

This Pricing Methodology is written to meet the requirements of both the Commission and the Authority. In Appendix A, we have listed the Commission's requirements under clause 2.4—Pricing and Related Information of the Information Disclosure Determination and described how we have met them. In Appendix B, we have listed the Authority's Pricing Principles and describe how we meet those.

The Commission uses the Information disclosure requirements[2] to measure our performance annually. The Authority developed Pricing Principles to drive efficient pricing through the:

- signalling of the economic costs of network use at a point in time or place; and
- recovering any shortfall in target revenue in a way that least distorts network use.

In May 2022, the Authority released its Edition 2.1, Practice Note, to assist distributors in applying the Pricing Principles; and in September 2022, sent an Open Letter to Distributors highlighting the Authority’s three main areas of focus for distribution pricing reform in 2022:

- options for promoting faster reform
- addressing pricing issues for new/expanded connections
- pass-through of the new transmission charges.

We have considered the Authority’s guidance and have taken steps to meet its expectations when setting this year's prices. We acknowledge that further work will be required in subsequent years.

1.3.1 Connection of Distributed Generation

We have approximately 1,106 distributed generation connections on our network (approximately 1% of connections). Most are small sites (less than 10kW) connected at 400V. We use standard charging for import meters and do not charge for distributing exported energy.

On 1 April 2021, we introduced an export price to help us monitor the uptake of distributed generation on our network. To reflect the uncertainty surrounding distributed generation, we set it at zero cents per kWh, and we have chosen to leave the price unchanged for this pricing year. We discuss our approach to distributed generation in Section 5.9.

1.3.2 Phase out of the Low Fixed Charges

As distributors, we are subject to the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 (LFC Regulations). The Authority monitors and enforces these regulations. The regulations require us to offer residential consumers a price option at their primary place of residence with a fixed price of no more than 60 cents per day (excluding GST) and where the sum of the annual fixed and volume charges on that price option equal any other permanent place of residence price option for the average consumer anywhere in New Zealand using up to 8,000 kWh per annum.

The fixed rate has increased by 15 cents each year following the government’s announcement in September 2021 to phase out the LFC regulations over the five years 2021 to 2026. More discussion about our approach to meeting the low fixed charge regulations can be found in Section 5.5.

1.4 DECARBONISATION IS A DRIVER FOR PRICE CHANGES

The use of Electric Vehicles (EV) and distributed energy resources (DER), such as solar photovoltaic (PV) generation and battery storage, is increasing. We endeavour to ensure the operation of our network and the services we provide (and the prices we charge for those services) are appropriate to meet customers’ needs.

[2] Section 54F of the Act.

Prices must reflect the benefits and impacts of EV and DER connected in customers' premises and how they interact with the network and new operational technologies. In the face of these changes, we anticipate adjusting consumption patterns and investment decisions by both customers and distribution businesses. Accordingly, there will be adjustments in price options to deliver cost-reflective and service-oriented prices.

We expect a positive benefit from the New Zealand Transport Agency, Waka Kotahi, completing two regional roading projects (Transmission Gully March 2022 and Peka Peka to Ōtaki December 2022) and preparing for the Ōtaki to North of Levin segment. Transmission Gully is providing improved travel times in and out of Wellington and surrounding areas, with a prediction this will encourage people to relocate from Wellington into the region. As larger households move into the region, it is anticipated there will be both increased average consumption and new ICP connections. It is also expected that heavy transport travel times will reduce across the region and as a result, we may see other industries relocating here. This will likely mark a significant change to our existing majority of low-use domestic customers.

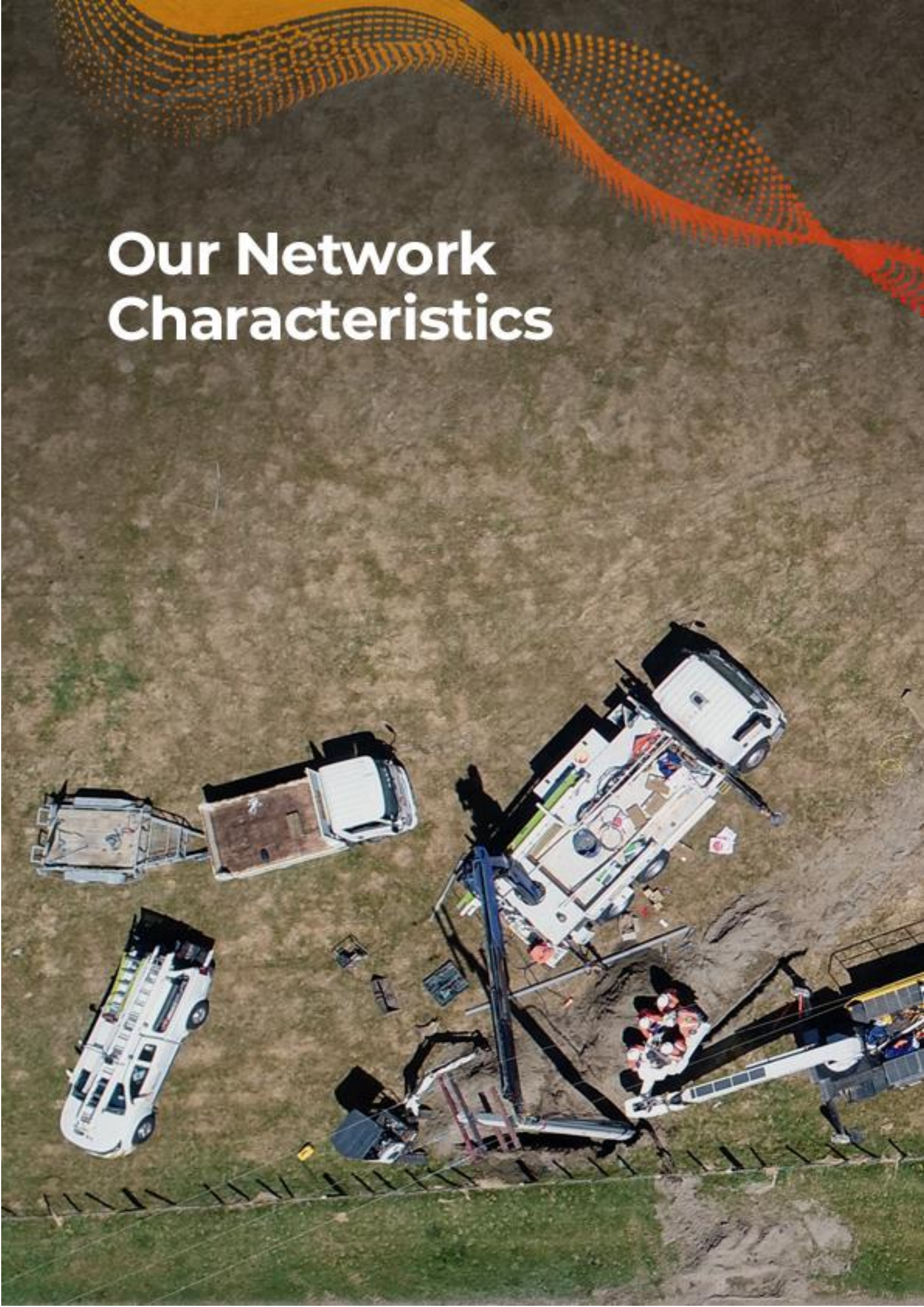
1.5 SUSTAINABILITY

We are committed to supporting the Government's reduction in emissions to meet obligations under the Paris Climate Agreement. Electra will seek opportunities to help decarbonise New Zealand by transitioning energy users in the region from fossil fuels to electricity. Any spare network capacity should be considered a critical asset in supporting activities such as the electrification of transport and the removal of carbon-based process heat.

We aim to support New Zealand's Carbon Neutral Government Programme through prices by providing pricing plans for export charging and flexible load. Our time of Use (TOU) pricing encourages customers to shift load to times when there is spare capacity, avoiding unnecessary augmentation of our distribution network.

Our focus on having capacity available where and when consumers want on a least cost basis is reflected in our annual Asset Management Plan (AMP) through our support of flexible technologies such as DER and greater numbers of EVs. Over the next three years, distributed energy resource management (DERMS) and flexibility services systems will enable us to plan better and demonstrate the ability to manage increased electrification. This will help us to manage the cost to serve being in the long-term best interest of our consumers.

Our Network Characteristics



2.1 NETWORK LOAD CHARACTERISTICS

Our network is electrically contiguous, supplied by two grid exit points (GXPs), Mangahao and Paraparaumu. The two GXPs serve very different market segments:

- our northern network is supplied predominantly from the Mangahao GXP and embedded Mangahao generation, supplying Levin, Foxton, and Shannon in a ring configuration. The local economy is strongly tied to primary production, which has demonstrated low but increasing growth in ICP numbers, demand, and volume.
- our southern network is supplied predominantly from the Paraparaumu GXP, supplying Paekākāriki, Paraparaumu East, Raumati, Waikanae and Ōtaki by a double spur configuration. This market segment has a broad demographic comprising a range of features, including strongly urbanised lifestyles and rural to agricultural production. Many people living in this area commute to Wellington, and the daytime demand is considerably less than the evening demand, leading to a low load factor. Changing work arrangements are, however, dampening this historic effect.
- across both network areas, we have several coastal settlements with holiday homes, atypical usage profiles and low energy profiles.

Approximately 41% of the energy conveyed through our network is via the northern network (i.e. the Mangahao GXP) and 59% through the southern network.

2.2 NETWORK GROWTH

The Horowhenua District's population is projected to grow at 1.8% per year over the next ten years[3]. The same study also found that population growth is quicker than the average of the past ten years (1.5% per year) but slower than the average of the past six years (2.1% per year). From the 2018 census[4] released by Statistics New Zealand, the district has a population of 32,949, which increased at a rate of 2% per year since 2013.

For the Kāpiti Coast District Council (KCDC), the Sense Partners median forecast has been identified as the baseline used as the forecast reflected an annual average rate of growth of 1.5%, which aligns with the growth rate Kāpiti had experienced from 1996 – 2020, and the rate of growth identified in KCDC's Long Term Plan 2021[5].

The 2018 census identified a population of 53,940 residents, which has grown 1.9% per annum since 2013. Internal migration to the region is another factor considered that is expected to drive up population numbers.

To meet this population growth, we have been investing in system growth on our network. Growth in our key network parameters over four years is shown in Table 1.

3 Sense Partners, Horowhenua Socio-Economic projects, Summary and methods, Projections update report, May 2020.

4 Statistics New Zealand, Dataset: Age and sex by ethnic group (grouped total responses), for census night population counts, 2006, 2013, and 2018 Censuses.

5 Kāpiti Coast District Council. Regional Housing and Business Development Capacity Assessment – Housing Update, May 2022.

Table 1: Network growth over 4-years to 31 March 2023

Parameter	2020	2021	2022	2023	% Increase 2020-2023
Avg. No. of consumer connections	45,192	45,562	45,950	46,333	+3%
Maximum demand (MW)	101	104	111	108	+7%
Annual electricity delivered (GWh)	415	421	424	429	+3%
Total circuit length (km)	2,323	2,330	2,354	2,380	+2%
Number of distribution transformers	2,563	2,572	2,613	2,636	+3%

2.2.1 Drivers of growth by location on our network

We are a multi-characteristic network. We have a large urban population, a significant commuter belt with Wellington, and support the farming community. Growth on our network is largely driven by Wellington house prices pushing people out into the surrounding districts where housing is more affordable. As expected, the opening of Transmission Gully in late 2022 has accelerated the growth of our network as the commute into Wellington has been reduced from over an hour to under 45 minutes on average. Table 2 provides a summary of the growth drivers for each zone substation on our network.

Table 2: Summary of the growth drivers by zone substation

Zone Substation	Nature of the growth	Average annual demand growth			Annual average population growth[6]
		2021	2022	2023	
Shannon	Lifestyle blocks around Tokomaru	1.8%	1.9%	5%	2.9%
Foxton	Residential development at Foxton Beach	2.7%	2.7%	3%	2.3%
Levin East	Commercial and lifestyle blocks to the south and east of Levin. Possible large off-peak industrial load growth	1.8%	2%	4%	2.2%
Levin West	Residential properties at Waitarere Beach and lifestyle properties to the north and west of Levin	1.9%	2%	3%	2.2%
Ōtaki	Lifestyle blocks in Manakau and Te Horo. Residential greenfield development in/near Ōtaki planned	2.2%	2.3%	4%	2.4%
Waikanae	Planned residential greenfield development in/near Waikanae	2.9%	2.8%	4%	3%
Paraparaumu East	Mainly commercial and residential infill	1.4%	1.7%	2%	1.7%
Paraparaumu West	Mainly commercial and residential infill	1.3%	2%	2%	1.7%
Raumati	Mainly residential infill	0.9%	1.2%	2%	1.6%
Paekākāriki	Mainly residential infill	0.8%	1.5%	5%	0.8%

6 Statistics New Zealand, Dataset: Age and sex by ethnic group (grouped total responses), for census night population counts, 2006, 2013, and 2018 Censuses (RC, TA, SA2, DHB).

2.3 NETWORK CAPACITY

Our network is designed and operated to meet forecasted electricity maximum demand up to the level of installed firm capacity and to provide a level of service (i.e. reliability) consistent with customers' expectations. As maximum demand reaches installed firm capacity limits, we must consider further investments in network capacity, or DER, to meet demand. Customer demand is, therefore, a key driver of existing and future distribution costs.

Our maximum network demand of 108 MW is below last year's maximum demand of 111 MW but higher than the three-year average of 105 MW, indicating that the decrease in 2023 is unlikely to be sustained. The maximum network demand is well below the zone substation installed capacity of 358 MW. However, there are localised constraints that require investment.

There is a Transpower-imposed terminal constraint at our Mangahao GXP. The limit of 38 MW means that at times during winter peak periods,[7] we use load control to ensure we are below the constraint. More specifically, forecast constraints at 11kV distribution and 400V reticulation are addressed in our AMP and are under review as part of our Energy Transformation Working Group.

2.4 CIRCUIT LENGTH

The circuit length required to transmit electricity from the GXP to customers is a key driver of network investment costs. Consumers situated further away from the main supply areas create relatively higher costs for us. However, compared with other distributors, our network is relatively compact.

Further, the ongoing meshing of the distribution network in urban centres and rural areas makes it difficult to distinguish line lengths for a particular consumer or group of consumers (due to the difficulty in tracking electrical flows). While consumer density decreases towards the edge of the network, most of the network length is shared across our entire consumer base.

2.5 CONSUMER-SPECIFIC ASSET USAGE

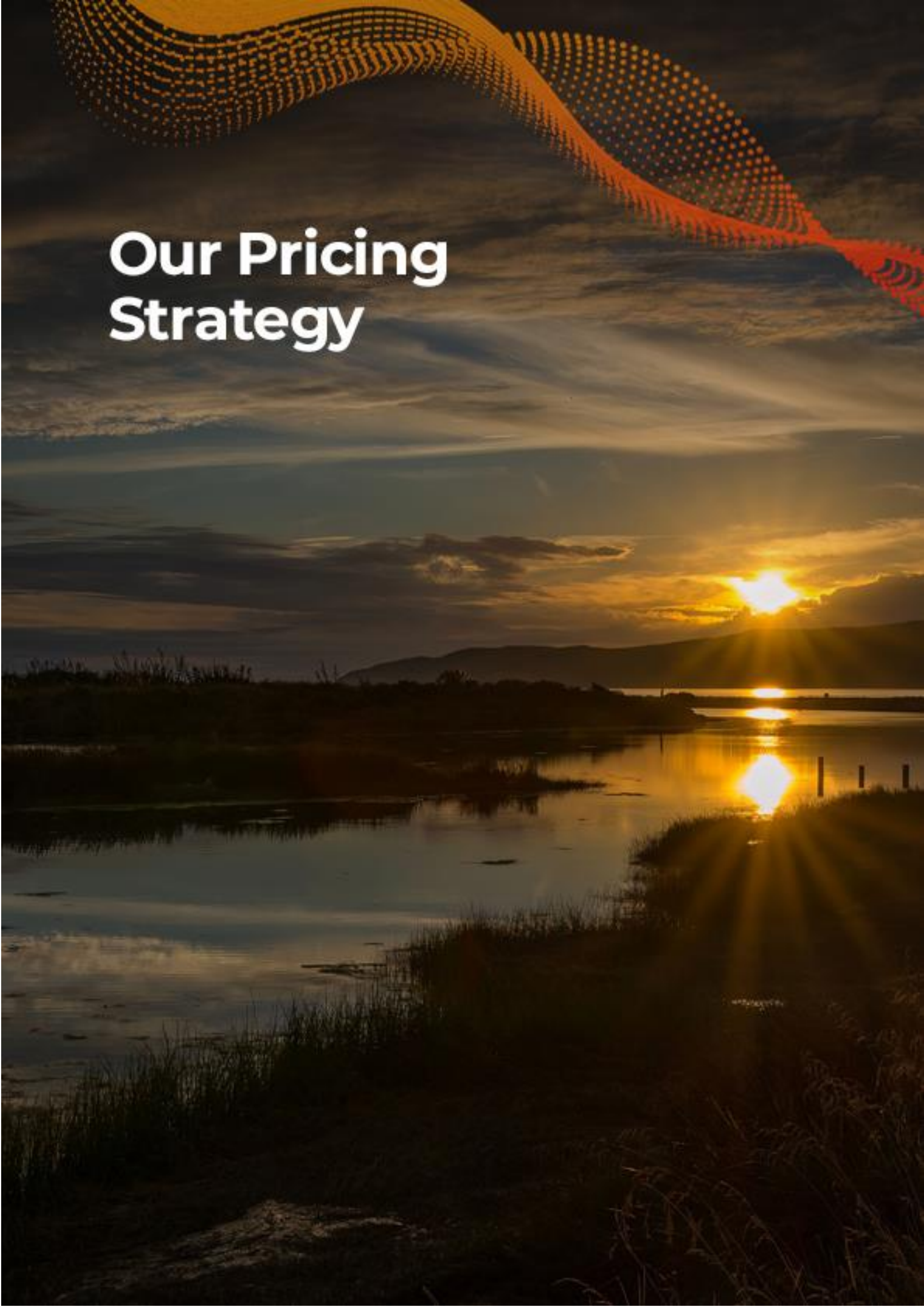
Where practical, the network costs related to a particular consumer or group of consumers are identified and recovered from those parties. Our approach aligns cost recovery with the beneficiary of those assets. Street lighting and community lighting are consumer groups that have specific assets that are identifiable and allocated to that group.

In 2013, we considered whether consumer-specific asset use could be better reflected in our pricing methodology. In particular, the use of high and low-voltage assets and dedicated equipment (i.e. transformers) was considered. We concluded there is very little variation in asset utilisation within our consumer base (e.g. less than 0.01% of consumers directly connect to 11kV feeders). However, this is beginning to change.

To reflect this change, on 1 April 2021, we introduced a zero-rated capacity charge for the Industrial User category that will increase to reflect the costs of dedicated equipment. For those consumers who require dedicated equipment, this has generally been dealt with as part of our network extension policy rather than through pricing. In the future, the network extension policy and pricing will be combined to have more cost-reflective pricing and asset allocation.

[7] During the 2021 winter peak, we needed to extend the load control periods for our northern network as our demand exceeded this limit.

Our Pricing Strategy



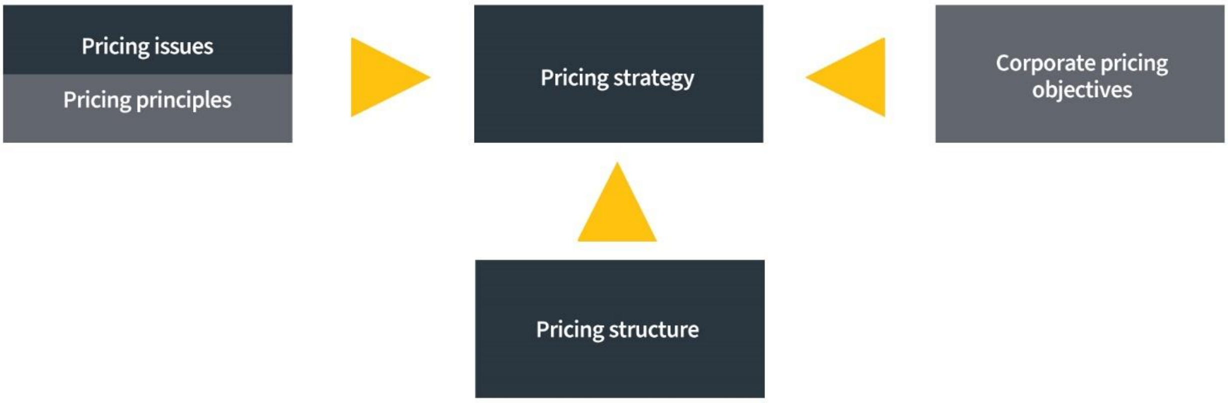
3.1 OUR PRICING STRATEGY

We aim to set prices that are efficient and appropriate. Each pricing year, we assess our prices against the Authority's measure of efficient pricing by ensuring we:

- signal the economic costs on our network; and
- where a revenue shortfall occurs, recover that shortfall in a way that least distorts network use.

Figure 3 shows the drivers of our pricing strategy and pricing structure.

Figure 3: Drivers of the pricing strategy and pricing structure



The Authority promotes the provision of cost-reflective distribution price options. We support this initiative and, together with the Electricity Networks Association (ENA), liaise with retailers to develop common approaches to make cost-reflective distribution pricing available and visible to end consumers within the overall retail price options.

We will meet our aim by introducing and refining service-oriented, progressive, and cost-reflective pricing to recover the network's economic costs and be responsive to the evolving market and consumers' changing ways of using the network.

The adoption of TOU pricing is a key step in this strategy. Our TOU prices are an iterative process requiring the fine-tuning of pricing signals and building the capability to measure and interpret the impact of changes in use.

Pricing is one tool we have. We will also investigate alternatives to capital works programmes, such as the development of flexibility services in lieu of network upgrades.

Our Pricing Objectives

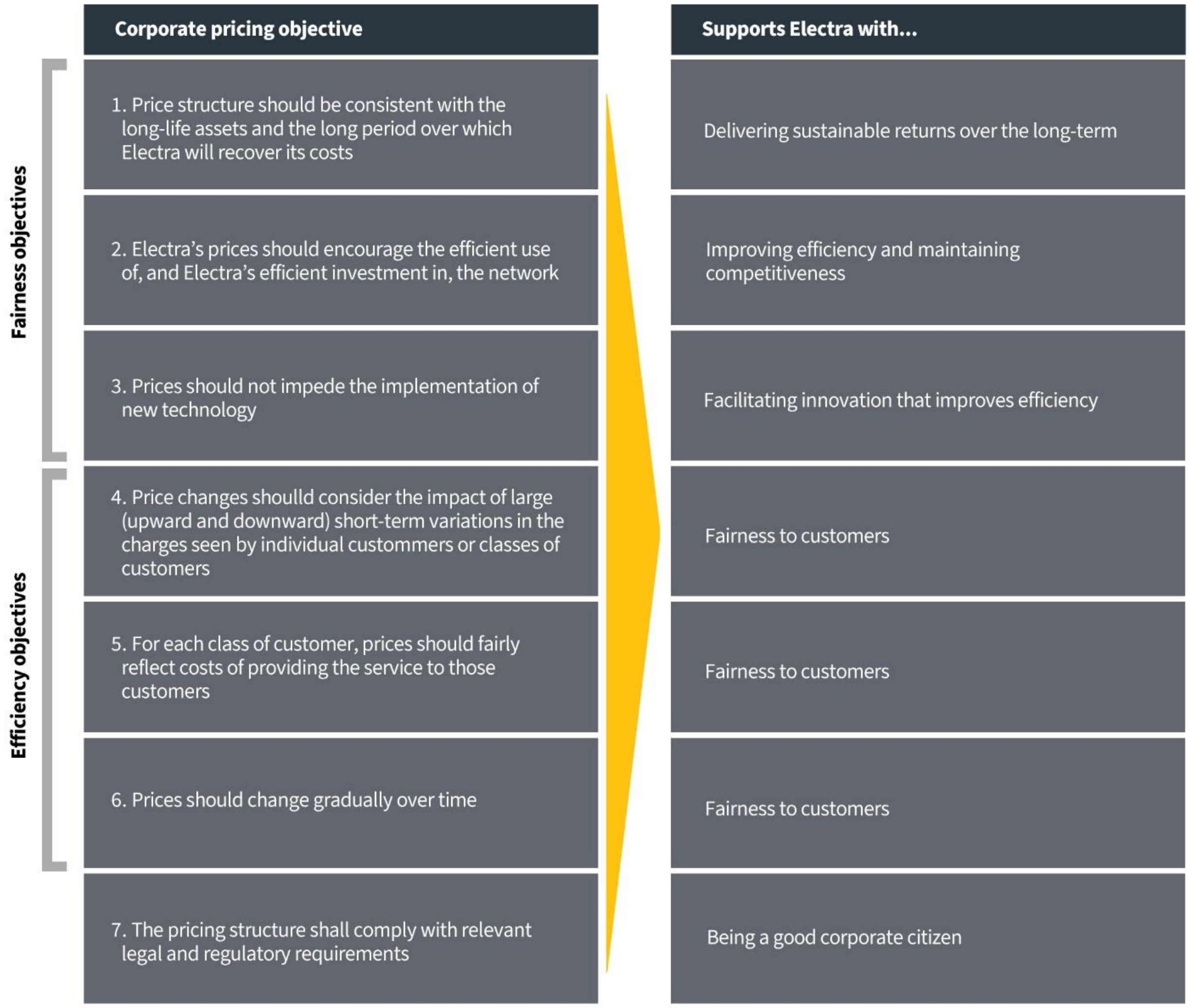
4.1 OUR PRICING OBJECTIVES

The emergence of alternative energy sources, changes in consumer demands, and an increased regulatory interest in pricing issues have led to a renewed focus on electricity line pricing. This increased focus has led us to undertake a strategic review of distribution line pricing arrangements to develop a long-term line pricing strategy.

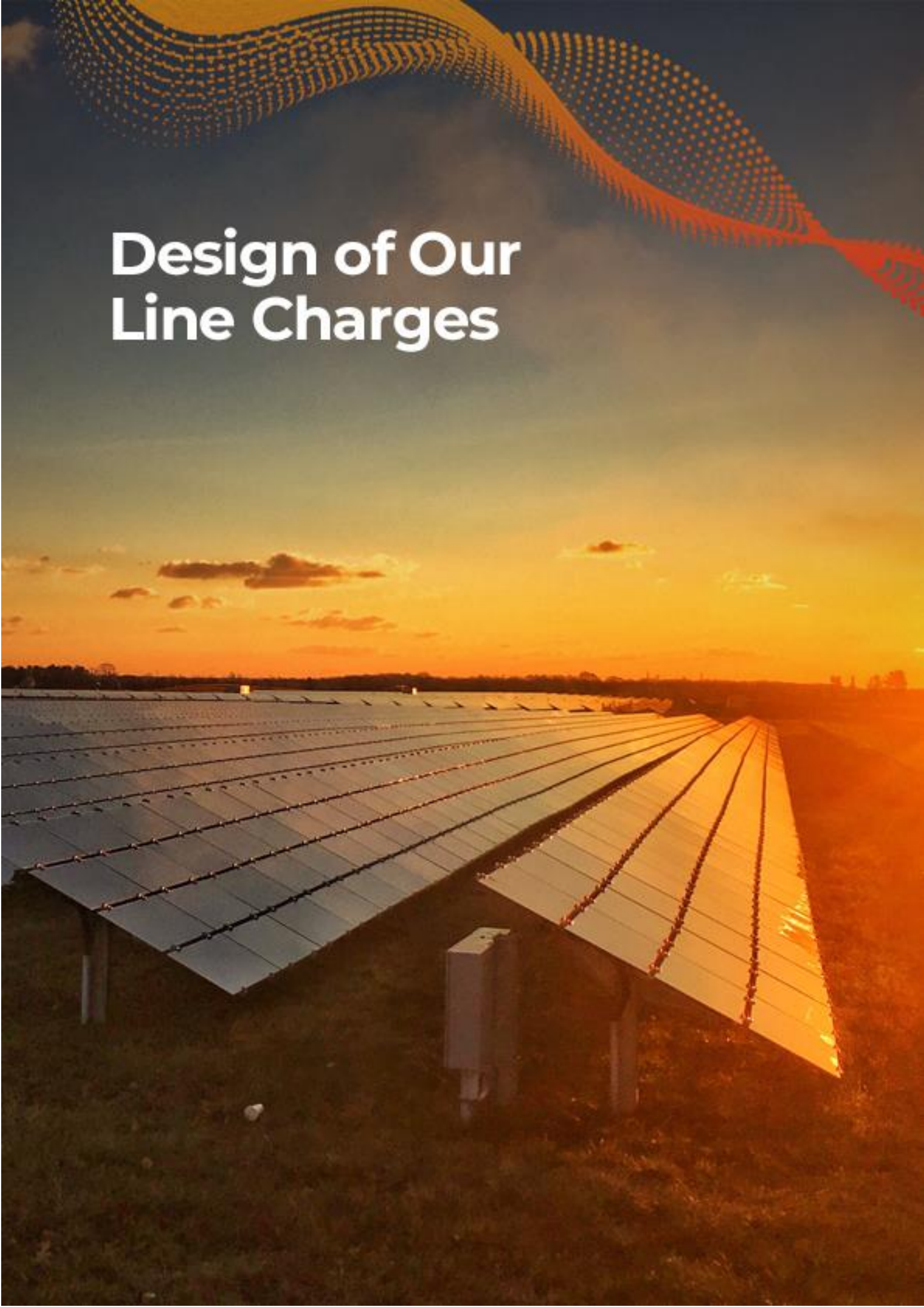
Our Statement of Corporate Intent defines our overall direction and performance expectations. For the Statement of Corporate Intent, we have developed a series of corporate pricing objectives. We believe the pricing strategy needs to be tested against these statements to ensure it will satisfy our corporate objectives.

Figure 4 shows our pricing objectives as they relate to the SCI and how we support those objectives.

Figure 4: Our corporate pricing objectives



Design of Our Line Charges



5.1 DESIGN OF OUR LINE CHARGES

Our prices are focused on the mass market (low and standard consumer groups) because small loads dominate the consumer base. Domestic and small commercial users represent approximately 97% of connections and 77% of consumption.

Mass market connections are low voltage, typically 60-amp single phase or 40-amp three phase. These consumers have a typical residential demand profile, which peaks in the morning and early evening.

Our pricing must also cater to large commercial loads. In contrast to the mass market, most large commercial loads have half-hourly metering and much higher annual consumption levels (ranging from 40,000 kWh to more than 3 GWh). Large commercial loads also have distinct demand behaviours, ranging from flat demand across the standard working day to highly variable demand that changes by time of day and season. From a cost driver perspective, large consumers have higher capacity connections and utilise a greater proportion of the installed network capacity relative to the average mass market connection.

All consumer groups are charged a variable price and a fixed daily charge. Fixed charges and variable prices are separated between distribution and transmission components, which seek to recover distribution and transmission costs.

Specific prices in the Low, Standard, and Industrial User consumer groups incorporate signals that enable consumers to achieve a lower overall cost of supply by shifting consumption to off-peak periods and offering interruptible load. This aligns our pricing incentives to the cost of network capacity and capacity utilisation.

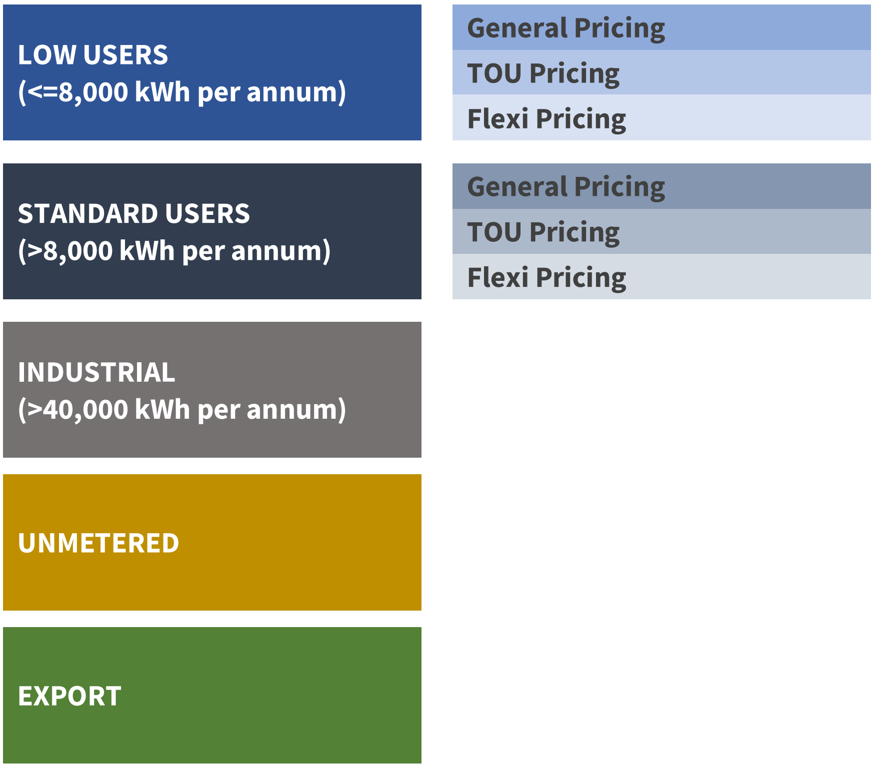
Each price category has been specified to achieve certain objectives. While we are mindful that retail price bundling may dilute distribution price signals, we recognise the consumer's choice will be influenced by the attractiveness of the retailer's overall bundle. In this context, we will continue to survey our connected consumers, transparently present our price options and work with industry participants to help provide clear cost-reflective distribution pricing signals to consumers.

5.2 CONSUMER GROUPS

In 2013, we established the three primary consumer groups as part of our pricing review. In 2023, as part of our pricing strategy review, we reevaluated these consumer groups and concluded that the groups remain relevant and have left these from last year. An explanation of our price options in tabular format is available in Appendix D — Delivery charges effective 1 April 2024.

Figure 5 shows the consumer groups and network charge categories effective 1 April 2024.

Figure 5: Consumer groups and network charge categories effective 1 April 2024



5.2.1 The consumer nominates the Consumer Group through their retailer

When connecting to our network, the consumer, via the retailer acting as the consumer's agent, nominates the consumer group they wish to be put into. We believe that the retailer is best placed to determine the most appropriate pricing option for the consumer based on that consumer's profile.

Table 3 lists the consumer groups in the pricing year, No. of ICPs, and the proportion of fixed vs. variable revenue collected from each.

Table 3: Consumer grouping to set prices

Consumer Group	Pricing Category	No. of ICPs	Fixed	Variable
Low Users (<=8,000 kWh per annum)	General Pricing	23,672	20%	80%
	TOU Pricing	14,671	21%	79%
	Flexi Pricing	11	30%	70%
Standard Users (>8,000 kWh per annum)	General Pricing	2,435	48%	52%
	TOU Pricing	5,424	46%	54%
	Flexi Pricing	5	62%	38%
Industrial (>40,000 kWh per year)		285	7%	93%
Unmetered		NA	83%	17%

5.3 FIXED CHARGE COMPONENTS

A fixed daily charge is applied to all consumers. We consider our fixed charge options appropriately recognise the following:

- investments in existing network capacity
- connection cost drivers
- our need for revenue stability
- the low fixed charge regulations
- the Authority's cost-reflective pricing initiative
- consumers' preference for cost stability.

5.4 VARIABLE CHARGE COMPONENTS

A variable price based on kWh consumption is applied to all price groups. The evolution of our time-of-use price categories to include control of hot water load continues to offer lower energy charges for residential consumers while recovering a greater proportion of our fixed costs through a higher daily charge. We intend to continue to evolve our pricing to recover costs via its fixed components. Together with our low fixed charge price categories, we offer a broad mix of options that:

- aligns with existing retail pricing structures,
- aligns with the LFC regulations, and
- introduces options with daily charges that more closely reflect the fixed costs of an EDB, which aligns with the Electricity Authority's cost-reflective pricing initiative.

5.4.1 Uncontrolled load price option

Consumers can elect for an uncontrolled price option (often in combination with controlled load price options). Approximately 50% of consumers have an uncontrolled connection. The uncontrolled price option recognises that these consumers can use the network at any time up to the capacity of their connection.

5.4.2 TOU charge components

Several of our price options are designed to incentivise efficient use of our existing network capacity by setting higher variable prices at peak periods and lower prices during the shoulder and off-peak periods.

We are progressively increasing the gap between the Peak and Night components of our TOU plans. The results will be a stronger differential to reflect the spare off-peak capacity and encourage consumers to shift their load out of the peak periods and into off-peak periods.

We intend to review these annually and change this differential in response to network usage and consumer behaviours.

With the previous introduction of an Electric Vehicle TOU option for consumers, we are signalling that residential users with high amounts of discretionary load can benefit from technologies that enable the load to be managed outside peak times. We will be exploring this further over the coming year.

5.4.3 Controlled load price categories

Controlled load price options, such as the Controlled 20 or Night Boost options, are also offered. These allow us to control load for up to four hours a day, typically during times of high demand, or to allow us to restore network faults.

We intend to review the controlled price options available over the pricing years to simplify this price category.

5.4.4 Power factor charges

We reserve the option to apply an additional charge where a commercial consumer has a power factor below 0.95 lagging. The charge will be based on a multiplier of 2% of the monthly total network charges for every 0.01 power factor below 0.95 lagging. This charge allows us to signal the need for improvements in power factors with the goal of avoiding unnecessary network reinforcement.

5.5 LOW USERS (<=8,000 KWH PER ANNUM)

Our Low User consumer category meets the low fixed charge regulations and is appropriate for consumers that use 8,000 kWh or less per annum.

Consumers in the Low User consumer group can choose between three price categories: General Pricing, TOU pricing, or Flexi Pricing (subject to suitable meter type). We offer a price category choice to allow consumers to select a pricing approach that best matches their energy consumption profile.

Fixed prices for all three categories are recovered on a per connection per day basis and are set per the low fixed charge regulations. Variable prices are recovered on a kWh consumption basis. Each pricing category offers consumers a selection of consumption prices. We have included a description for each price category under the Low User consumer group in Table 4 to Table 6.

5.5.1 General Pricing categories available under the Low User consumer group

We have forecast that approximately 23,672 consumers will be in our Low User, General Pricing category this pricing year, representing 50% of total consumers.

The General Pricing category is likely to align with consumers who have no interest in or can have little effect on their consumption. While shifting to another price category of consumer group could reduce a consumer's bill, such a move may not and, in some circumstances, could increase their bill, particularly if that consumer has no interest in when they consume electricity or is not able to change their consumption profile actively.

Table 4: Description of the General Pricing categories available under the Low User consumer group

Pricing Category	Description	% Total Consumption
Uncontrolled/Anytime	A flat rate that applies 24 hours a day, 7 days a week, 365 days a year. Also referred to as 'all you can eat', this price option sends no signal to the consumer as to how their behaviour drives costs, and as such, it is the highest consumption price choice at— • 15% higher than the Night/Day option • 18% higher than the TOU Pricing category • 19% higher than the Flexi Pricing category The Uncontrolled/Anytime price category is effective for those consumers who have little interest or ability to change their consumption patterns and are satisfied to pay a higher price to do so. It is appropriate that we collect more from these consumers as their behaviours are driving more of our future costs than those consumers who are interested in responding to our price signals.	74%
Night of Day/Night (9pm-7am)	A simple time-of-use price that encourages consumers to consume at night, i.e., in the off-peak period, by rewarding consumers with a price that is 52% lower than the Uncontrolled/Anytime price. The Night price category is effective for those consumers who want to reduce their line charges and are willing and able to shift some consumption out of our peaks. Consumers do not need to shift all consumption, but rather discretionary consumption such as washing machines, dryers, and dishwashers. We consider it appropriate that consumers be rewarded for shifting load as their change in behaviour reduces our future costs.	2%
Day of Day/Night (7am-9pm)	A simple time-of-use price that discourages consumers from consuming during the day, i.e., in the peak period, by charging consumers a price 11% higher than the Uncontrolled/Anytime price. The Day price category is effective for those consumers who want to reduce their line charges and are willing to shift some consumption out of our peaks. Though higher than the Uncontrolled/Anytime price, the corresponding saving for shifting consumption to off-peak (i.e., at night) compensates for the practicalities of needing to consume electricity during the day to support everyday realities such as lighting, cooking, and heating. It is appropriate that consumers be rewarded for the consumption they can shift into our off-peak period as a change in behaviour reduces our future costs.	2%
Controlled 20 (electric hot water)	A legacy price that rewards consumers for giving us control of their hot water cylinders. We can control the hot water load for up to 4 hours a day and, in return, charge consumers a price that is 37% lower than the Uncontrolled/Anytime price.	20%
Night only (11pm-7am)	A legacy price that was intended to support night store heaters. There are currently no consumers in this price category, and we are considering withdrawing this price category from 1 April 2025.	NA
Night Boost (11pm-7am & 1pm-4pm)	A legacy price that supports controlled hot water by giving consumers the option to heat water once a day during our shoulder periods. The price encourages consumers to give us control of their hot water load in return for a price that is 41% lower than the Uncontrolled/Anytime price.	1%

5.5.2 TOU Pricing categories available under the Low User consumer group

We have forecast that approximately 14,671 consumers will choose to be in our Low User, TOU Pricing category this pricing year, representing 31% of total consumers.

This price category will likely align with consumers who are actively interested in managing when they consume electricity. Where a consumer can actively shift consumption into off-peak periods, shifting from the General Pricing category to the TOU Pricing category could reduce the average consumer line charges.

Table 5: Description of the TOU Pricing categories available under the Low User consumer group

Pricing Category	**Description**	**% Total Consumption**
Off-Peak (11pm-7am)	A more sophisticated time-of-use price than the General Pricing, Day/Night category that encourages consumers to shift their consumption into the off-peak periods by rewarding consumers with a price that is 55% lower than the Uncontrolled/Anytime price.	18%
Peak (7am-11am & 5pm-9pm)	A more sophisticated time-of-use price than the General Pricing, the Day/Night category discourages consumers from consuming in peak periods by charging a price that is 18% higher than the Uncontrolled/Anytime price.	31%
Shoulder (11am-5pm & 9pm-11pm)	A more sophisticated time-of-use price than the General Pricing, Day/Night category encourages consumers to shift their consumption into the shoulder periods by rewarding consumers with a price that is 17% lower than the Uncontrolled/Anytime price.	20%
Controlled 20 (electric hot water)	A legacy price that rewards consumers for giving us control of their hot water cylinders. We can control the hot water load for up to 4 hours a day and, in return, charge consumers a price that is 37% lower than the Uncontrolled/Anytime price.	30%
Night Boost (11pm-7am & 1pm-4pm)	A legacy price that supports controlled hot water by giving consumers the option to heat water once a day during our shoulder periods. The price encourages consumers to give us control of their hot water load in return for a price that is 41% lower than the Uncontrolled/Anytime price.	2%

5.5.3 Flexi Pricing categories available under the Low User consumer group

We have forecast that approximately 11 consumers will choose to be in our Low User, Flexi Pricing category this pricing year, representing 0.02% of total consumers. This price category will likely align with consumers who have highly discretionary loads that can be actively managed, such as EVs and battery storage. Flexi Pricing is not for all consumers and could result in a perverse outcome if consumers elect for this price category and do not or cannot shift consumption into the off-peak period.

Table 6: Description of the Flexi Pricing categories available under the Low User consumer group

Pricing Category	Description	% Total Consumption
Off-Peak (11pm-7am)	Provides a strong signal to consumers to shift their consumption into the off-peak periods by rewarding consumers with a price that is 56% lower than the Uncontrolled/Anytime price.	46%
Peak (7am-11am & 5pm-9pm)	Strongly discourages consumers from consuming in peak periods by charging a price that is 9% higher than the Uncontrolled/Anytime price.	32%
Shoulder (11am-5pm & 9pm-11pm)	Provides a pricing signal encouraging consumers to shift their consumption out of the peak and into the shoulder periods by rewarding consumers with a price that is 10% lower than the Uncontrolled/Anytime price.	17%
Controlled 20 (electric hot water)	A legacy price that rewards consumers for giving us control of their hot water cylinders. We can control the hot water load for up to 4 hours a day and, in return, charge consumers a price that is 37% lower than the Uncontrolled/Anytime price.	4%

5.6 STANDARD USERS (>8,000 KWH PER ANNUM)

Our Standard User consumer category is appropriate for consumers that use more than 8,000 and less than 40,000 kWh per annum.

Consumers in the Standard User consumer group can choose between three price categories: General Pricing, TOU pricing, or Flexi Pricing. We offer a price category choice so consumers can select a pricing approach that best matches their energy consumption profile.

Fixed prices for all three categories are recovered on a per connection per day basis. Variable prices are recovered on a kWh consumption basis. Each pricing category offers consumers a selection of consumption prices. We have included a description for each price category under the Low User consumer group in the following tables, Table 7 to Table 9.

We have forecast that approximately 5 consumers will choose to be in our Low User, Flexi Pricing category this pricing year, representing 0.01% of total consumers. This price category will likely align with consumers who have highly discretionary loads that can be actively managed, such as EVs and battery storage. Flexi Pricing is not for all consumers and could result in a perverse outcome if consumers elect for this price category and do not or cannot shift consumption into the off-peak period.

5.6.1 General Pricing categories available under the Standard User consumer group

We have forecasted that approximately 2,435 consumers will choose to be in our Standard User, General Pricing category this pricing year, representing 5% of total consumers.

This price category is likely to align with consumers who have no interest or can have little effect on their line charges. While shifting to another price category or consumer group could reduce a consumer's line charges, such a move may not and could even increase their charges if that consumer has no interest in when they consume electricity or is not able to change their usage profile actively.

Table 7: Description of the General Pricing categories available under the Standard User consumer group

Pricing Category	**Description**	**% Total Consumption**
Uncontrolled/Anytime	A flat rate that applies 24 hours a day, 7 days a week, 365 days a year. Sometimes referred to as an 'all you can eat tariff,' this price option sends no signal to the consumer as to how their behaviour drives costs, and as such, it is the highest consumption price choice at: • 11% higher than the night/day option • 29% higher than the TOU Pricing category • 32% higher than the Flexi Pricing category The Uncontrolled/Anytime price category is effective for those consumers who have little interest, or no ability, to change their consumption patterns and are satisfied to pay a higher price to do so. It is appropriate that we collect more from these consumers as their behaviours are driving more of our future costs than those consumers who are interested in responding to our price signals.	87%
Night of Day/Night (9pm-7am)	A simple time-of-use price that encourages consumers to consume at night, i.e., in the off-peak period, by rewarding consumers with a price that is 86% lower than the Uncontrolled/Anytime price. The Night price category is effective for those consumers who want to reduce their line charges and are willing and able to shift some consumption out of our peaks. Consumers do not need to shift all consumption, but rather discretionary consumption such as washing machines, dryers, and dishwashers. We consider it appropriate that consumers be rewarded for shifting load as their change in behaviour reduces our future costs.	1%

Pricing Category	Description	% Total Consumption
Day of Day/Night (7am-9pm)	A simple time-of-use price that discourages consumers from consuming during the day, i.e., in the peak period, by charging consumers a price that is 18% higher than the Uncontrolled/Anytime price. The Day price category is effective for those consumers who want to reduce their line charges and are willing to shift some consumption out of our peaks. Though higher than the Uncontrolled/Anytime price, the corresponding saving for shifting consumption to off-peak (i.e., at night) compensates for the practicalities of needing to consume electricity during the day to support everyday realities such as cooking and heating. It is appropriate that consumers be rewarded for the consumption they can shift into our off-peak period as a change in behaviour reduces our future costs.	1%
Controlled 20 (electric hot water)	A legacy price that rewards consumers for giving us control of their hot water cylinders. We can control the hot water load for up to 4 hours a day and, in return, charge consumers a price that is 60% lower than the Uncontrolled/Anytime price.	10%
Night only (11pm-7am)	A legacy price that was intended to support night store heaters. In return for consumers only consuming during the night, we charge a price that is 73% lower than the Uncontrolled/Anytime price.	0.1%
Night Boost (11pm-7am & 1pm-4pm)	A legacy price that supports controlled hot water by giving consumers the option to heat water once a day during our shoulder periods. The price encourages consumers to give us control of their hot water load in return for a price that is 68% lower than the Uncontrolled/Anytime price.	0.4%

5.6.2 TOU Pricing categories available under the Standard User consumer group

We have forecasted that approximately 5,424 consumers will choose to be in our Standard User, TOU Pricing category this pricing year, representing 11% of total consumers. This price category will likely align with consumers who are actively interested in managing when they consume electricity.

This price category will likely align with consumers who are actively interested in managing when they consume electricity. Where a consumer can actively shift consumption into off-peak periods, shifting from the General Pricing category to the TOU Pricing category could reduce the average consumer line charges.

Table 8: Description of the TOU Pricing categories available under the Standard User consumer group

Pricing Category	Description	% Total Consumption
Off-Peak (11pm-7am)	A more sophisticated time-of-use price than the General Pricing, day/night category that encourages consumers to shift their consumption into the off-peak periods by rewarding consumers with a price that is 90% lower than the Uncontrolled/Anytime price.	21%
Peak (7am-11am & 5pm-9pm)	A more sophisticated time-of-use price, the General Pricing, day/night category than day/night, discourages consumers from consuming in peak periods by charging a price that is 30% higher than the Uncontrolled/Anytime price.	40%
Shoulder (11am-5pm & 9pm-11pm)	A more sophisticated time-of-use price than the General Pricing, day/night category that encourages consumers to shift their consumption into the shoulder periods by rewarding consumers with a price that is 28% lower than the Uncontrolled/Anytime price.	28%
Controlled 20 (electric hot water)	A legacy price that rewards consumers for giving us control of their hot water cylinders. We can control the hot water load for up to 4 hours a day and, in return, charge consumers a price that is 60% lower than the Uncontrolled/Anytime price.	11%
Night Boost (11pm-7am & 1pm-4pm)	A legacy price that supports controlled hot water by giving consumers the option to heat water once a day during our shoulder periods. The price encourages consumers to give us control of their hot water load in return for a price that is 68% lower than the Uncontrolled/Anytime price.	0.1%

5.6.3 Flexi Pricing categories available under the Standard User consumer group

We have forecast that approximately 5 consumers will choose to be in our Low User, Flexi Pricing category this pricing year, representing 0.01% of total consumers. This price category will likely align with consumers who have highly discretionary loads that can be actively managed, such as EVs and battery storage. Flexi Pricing is not for all consumers and could result in a perverse outcome if consumers elect for this price category and do not or cannot shift consumption into the off-peak period.

Table 9: Description of the Flexi Pricing categories available under the Standard User consumer group

Pricing Category	Description	% Total Consumption
Off-Peak (11pm-7am)	Provides a strong signal to consumers to shift their consumption into the off-peak periods by rewarding consumers with a price that is 92% lower than the Uncontrolled/Anytime price.	36%
Peak (7am-11am & 5pm-9pm)	Strongly discourages consumers from consuming in peak periods by charging a price that is 14% higher than the Uncontrolled/Anytime price.	34%
Shoulder (11am-5pm & 9pm-11pm)	Provides a pricing signal encouraging consumers to shift their consumption out of the peak and into the shoulder periods by rewarding consumers with a price that is 17% lower than the Uncontrolled/Anytime price.	22%
Controlled 20 (electric hot water)	A legacy price that rewards consumers for giving us control of their hot water cylinders. We can control the hot water load for up to 4 hours a day and, in return, charge consumers a price that is 60% lower than the Uncontrolled/Anytime price.	8%

5.7 INDUSTRIAL USERS (>40,000 KWH PER ANNUM)

The Industrial User category applies to a connection that uses more than 40,000 kWh per annum. These consumers are large energy users, including commercial premises used for commercial, retailing, processing, and manufacturing.

Industrial Users have multiple uses of electricity, from energy-intensive functions such as freezing, refrigeration, process heat, and operating machinery to light uses such as back-office functions. Industrial Users account for approximately 1% of ICPs and 23% of consumption on our network.

5.8 UNMETERED LOAD

Last pricing year (i.e., 1 April 2023), we removed the variable charges for most of our community lighting. We added a standard fixed price that recognises increasing replacement costs and the lower consumption of LED lights. The change recognises network capacity utilisation and the costs attributable to dedicated assets such as street lighting circuits and poles.

5.9 EXPORT

On 1 April 2021, we introduced an export price to help us monitor the uptake of distributed generation on the network. The Export price is currently set at zero cents per kWh, meaning we neither charge nor pay consumers with distribution generation on our network.

We currently do not make direct payments to distributed generation for the avoided cost of transmission or distribution as it is not practical. Avoided costs are recognised by not charging generators for injection into the network.

Consistent with the incremental cost pricing principle under Part 6 of the Electricity Industry Participation Code, should incremental costs arise in the future, we may amend our approach and recover the incremental costs driven by distributed generation.

5.9.1 Approximately 2% of ICPs on our network have small-scale distributed generation connected

We have approximately 1,106 DG installations connected to our network, accounting for 2% of connections. Most are small sites (less than 10kW) connected at 400V. We use standard charging for import meters and do not charge for distributing exported energy.

5.9.2 We have one large, embedded generator on our network

Mangahao power station near Shannon is embedded in our network. When Mangahao generates during transmission peaks it reduces peak grid demand and lowers our transmission charges derived under the Transmission Pricing Methodology. We recognise that shared benefit through an avoided cost of distribution (ACOD) payment.

5.10 STANDARD AND NON-STANDARD CONNECTION CONTRACTS

5.10.1 All consumers are under a Standard Connection Contract

We supply electricity distribution services to consumers via electricity retailers (e.g., Contact, Genesis, Mercury, Flick, Merdian, etc.) under our Default Distributor Agreement (the DDA). Currently, all consumers on our network are under standard connection contract terms and conditions through our DDA.

5.10.2 There are no consumers under a Non-standard Connection Contract

We do not currently supply consumers under non-standard connection contract terms and conditions.

A non-standard connection contract reflects the unique nature of a consumer. For example, a connection might require significant network investment through dedicated assets. Price-quality trade-offs might result in a consumer having reduced or enhanced supply quality outside our normal operations mode.

Suppose a consumer was to approach us with connection needs outside of the terms of our standard connection contract (i.e., unique). In that case, we would negotiate a non-standard connection contract with the consumer that meets their circumstances.

5.11 CONSUMER CONSULTATION AND PRICE-QUALITY TRADE-OFF

We consult with the Electra Trust on price and quality as part of our Statement of Corporate Intent process. We believe the Electra Trust is an effective advocacy body for representing the price-quality expectations and preferences of all standard connection contract consumers.

The Trustees are elected triennially by all connected consumers eligible to vote in those elections. The Trustees are highly accessible by consumers connected to our network. In addition, annually, we undertake a targeted research survey of consumer preferences related to price-quality trade-offs.

Through ongoing engagement with the Trust and periodic surveys, our feedback indicates that consumers are satisfied with the current price and quality trade-offs. Formal benchmarking studies undertaken as part of our five-yearly ownership reviews indicate that we are consistently in the top quartile of SAIDI reliability performance. Once the annual network discount is considered, our prices remain low relative to our peer group.

5.12 LOSS FACTORS

Losses are the percentage of electricity entering the network lost during the delivery to consumers' connections (i.e., ICPs). We calculate and publish our Reconciliation Loss Factors for all loss factor codes on our network annually. Losses include energy losses from the point of transmission connection at the grid exit points (GXP) to the point of connection for all consumers.

These energy losses can be categorised as:

- technical losses
- non-technical losses
- reconciliation losses
- unaccounted for electricity.

The loss factors for the pricing year are shown in Table 10.

Table 10: Losses for the Pricing Year

Loss Factor Code	1
Network Losses (%)	6.60%
Loss Factor	1.071

Annually, we publish our Network Loss Methodology, which was developed in line with the Authority's Guidelines[8]. A copy of our methodology can be found on our website.

5.13 CAPITAL CONTRIBUTIONS

In addition to distribution prices, consumers are required to fully fund the cost of their connection assets at the time of connection. Connection assets include additional 11kV and 400V power lines, cables, and transformers required to provide the electrical load and quality of supply sought by consumers. Where these assets are vested with us, we will pay for the ongoing maintenance and operation of the assets. We may also contribute to the costs where the required asset upgrade exceeds the consumer's requirements, and there is a network benefit from the upgrade.

Distribution prices do not seek to recover connection costs paid for by consumers under our Network Extension policy. Further information on our network extension policy can be found on our website.

8 Electricity Authority, Guidelines on the calculation and use of loss factors for reconciliation purposes, 26 June 2018.

Implementing Future Prices

6.1 REFORM OF ELECTRICITY DISTRIBUTION PRICES

Since November 2019, the Authority has led an industry-wide initiative urging electricity distributors to adopt cost-reflective and efficient distribution pricing structures as a matter of urgency. The impetus of the reform being:

> '*Distributors urgently need to improve the efficiency of their distribution prices because technology is rapidly changing how electricity is produced and consumed. These changes affect how distribution networks are used, and how distribution services should be priced. Cost-reflective pricing is for the long-term benefit of consumers, by ensuring that distributors make efficient investments in their networks and consumers make efficient network use decisions and investments in solar power, batteries, and electric vehicles.*'[9]

We have been reforming our prices since 2020 to meet the Authority's pricing expectations while at the same time having regard for the impact pricing reform has on our consumers.

The changes we have made to our pricing for 1 April 2024, our fourth transitional year, have been minor and have not required a material change to our pricing methodology. As we transition our prices, the changes we will make in the coming years could be material. In this case, we will consult with consumers and consider applying a glide path to manage the impacts on consumers, where appropriate.

6.2 ROADMAP OF OUR 5-YEAR JOURNEY TO COST-REFLECTIVE PRICING

In our 2021 Pricing Methodology,[10] we outlined our 5-year pricing strategy (i.e., 1 April 2021 to 1 April 2024). Our strategy considered short-term gains and long-term goals, including our intentions to:

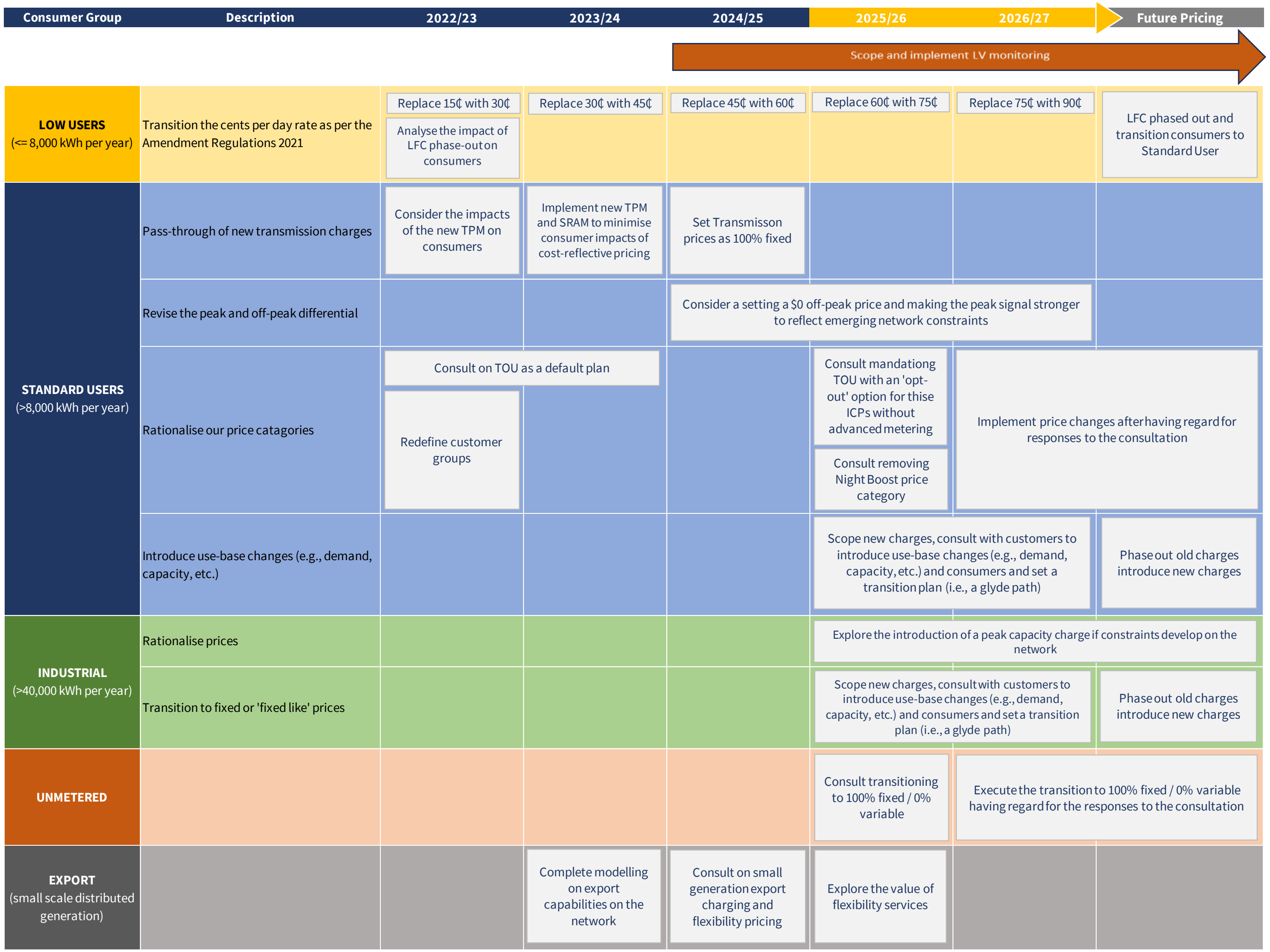
- adjust our price options developed from the cost of supply model, including the assessment of our long-run marginal costs
- progressively increase our cost recovery through fixed price components and conversely reduce variable prices over time
- improve the attractiveness of time-of-use (TOU) price options for consumers who can shift their peak demand to periods when the grid and generation have greater available capacity
- introduce capacity charge component for large consumers
- in response to the changes in the transmission pricing methodology, reduce control price options
- target appropriate pricing structures to support large, embedded generation projects such as solar farms to connect to our network
- signal TOU plans to be mandated for all connections with smart metering.

Over the last three years, we have progressed our strategy, and in this pricing year, the fourth year of our transitional journey, we have made further steps to realise our long-term goals. This year, we have rebuilt our cost-of-supply model, increased the portion of required revenue through fixed prices, and increased the pricing differential for TOU prices to send a stronger pricing signal.

Based on our progress, we have updated our 5-year pricing strategy and roadmap in this Pricing Methodology. Figure 6, visualises our 5-year journey.

9 Electricity Authority, Distributors' Pricing 2019 Baseline Assessment, 19 November 2019, paragraph 1.1.
10 Electra Limited, Electricity Distribution Business Pricing Methodology, Effective from 1 April 2021, 26 February 2021.

Figure 6: Electra 5-year pricing road map



6.3 CHANGES TO THE LOW FIXED CHARGE REGULATIONS HAVE BEEN AN ENABLER

In November 2021, the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Amendment Regulations 2021 came into force. The amendment regulations intend to phase out the low fixed charges over five years by allowing the regulated distributor tariff option to increase each year by 15 cents, as shown in Table 11.

Table 11: Stages of the low user charges phaseout

Year 1	1 April 2022 to 31 March 2023	15 cents to 30 cents
Year 2	1 April 2023 to 31 March 2024	30 cents to 45 cents
Year 3	**1 April 2024 to 31 March 2025**	**45 cents to 60 cents**
Year 4	1 April 2025 to 31 March 2026	60 cents to 75 cents
Year 5	1 April 2026 to 31 March 2027	75 cents to 90 cents

The phase-out of the low fixed charges has been an enabler in meeting the Authority's pricing reform expectations. Allowing distributors to increase the fixed charge has enabled us to pass-through transmission charges, increase the fixed proportion of cost recovery, and increase peak differentials, thereby sending a stronger pricing signal.

The regulations will be revoked on 1 April 2027, which will further support us in completing our transition to more cost-reflective and efficient pricing.

6.4 SUMMARY OF THE CHANGES WE MADE FOR 1 APRIL 2024

We started our journey in April 2022 by making several structural changes to our pricing approach, the first transitional year. The price signals have been adjusted from last year to be more consistent across price categories and more appropriate to the level of network constraint. We expect this to be an ongoing exercise, as the bundling of price options means that not every consumer sees and responds to our price signals. We see this as a limitation on how consumer behaviours can mature to respond to price signals in a timely manner. A summary of the changes we have made to prices is listed in Table 12.

Table 12: Summary of the changes made to our pricing approach effective 1 April 2024

<table>
<tr><th colspan="2">Consumer Group</th><th>Description of the changes made effective 1 April 2024</th></tr>
<tr><td rowspan="4">Low Users
(<=8,000 kWh per year)

and

Standard Users
(>8,000 kWh per year)</td><td>General Pricing</td><td rowspan="3">Recovering more of our costs to serve through fixed charges reflects the fixed-cost nature of distribution services. Accordingly, we have increased the fixed daily charges.
Low Users — Fixed daily charges were increased by 15 cents (or +33%) as per the amendment regulations.
Standard Users — Fixed Charges were increased by 43 cents (or +33%).
To offset the increase in fixed charges for both groups, we have decreased the volumetric charges. We have also made the peak price signals stronger by increasing the peak price differential compared to the off-peak price.</td></tr>
<tr><td>TOU Pricing</td></tr>
<tr><td>Flexi Pricing</td></tr>
<tr><td>Flexi Pricing</td><td>We have changed the name from ‘EV TOU Pricing’ to ‘Flexi Pricing’. We introduced the EV TOU Pricing group in April 2021 as a trial to inform the impacts of EVs on our network. The uptake was minimal, leading us to consider stopping the trial and withdrawing the group. Instead, in support of the MDAG final report on price discovery in a renewables-based electricity system, released in December 2023, we have decided to continue the trial and changed the consumer group name to provide consumers with flexible load (i.e., EV owners, embedded generation, and battery storage) lines charges that support their investment decision.

Because this consumer group is a trial, we will cap the number of participating consumers to 200 combined in the Low User and Standard User groups. We consider 200 ICPs to provide an incentive to retailers to switch consumers that could benefit from the prices and, at the same time, are a manageable number of ICPs for us to conduct a trial.</td></tr>
<tr><td colspan="2">Industrial

(>40,000 kWh per year)</td><td>Increased the fixed daily charge by $1.02 (or +33%). We took the opportunity this year to transition consumers in the Industrial Consumer Group to more fixed charges. We intend to continue the transition over several pricing years. Recovering more of our costs to serve through fixed charges reflects the fixed-cost nature of distribution services. To offset the increase in fixed daily charges, we have decreased the Off-peak (11pm-7am) prices.</td></tr>
<tr><td colspan="2">Unmetered</td><td>Remains largely unchanged with only a small increase to the fixed daily charge per fitting of +$0.0006 (or +0.3%).</td></tr>
<tr><td colspan="2">Export</td><td>Remains unchanged.</td></tr>
</table>

Delivery charges effective 1 April 2024 and a comparison with those effective 1 April 2023 are included in Appendix C.

6.5 OUR PRICES ARE FREE FROM MATERIAL CROSS-SUBSIDISATION

Our 1 April 2024 prices are free from material cross-subsidisation as we return our costs-to-serve from the prices applicable to each consumer group in full. A comparison of the Required Revenue and Target Revenue by consumer group can be found in Section 8.5 in Table 41.

6.5.1 Why do we apply uniform delivery charges

For the pricing year, we have decided to continue applying a uniform delivery charge that is indifferent to location and includes both distribution and transmission prices. Our decision results in consumers connected to the Paraparaumu GXP paying approximately +$3.73 (or +0.03%) per ICP per year, more than their costs to serve.

This amount is immaterial and indicates that our choice to retain uniform prices is efficient and appropriate.

We appreciate that our decision to apply uniform delivery charges does not necessarily meet the Authority's view of efficient pricing, as detailed in its Practice Note[11]. However, the Authority recognised the importance of weighing the cost vs. benefits of adopting greater granularity in its Practice Note:

> "*Granularity matters. The prices and regulated charges for electricity services vary significantly at different times and locations in electricity networks. Progressively improving the temporal and locational granularity of prices and charges can deliver increased social welfare;* ***however, these benefits must be balanced against the costs, complexity, and potential equity concerns of implementation***."[12] [Emphasis added]

We will reconsider applying uniform delivery charges before setting prices each year.

6.6 CONSUMER ENGAGEMENT

Each year, we survey our consumers to understand their views on prices, quality of supply, and consumption patterns. Our consumer survey represents a broad cross-section of our consumer base. We use the consumer survey results to measure our strategy's effectiveness and inform our plans, such as forecast expenditure in our AMP, pricing plans, and communication approaches.

Our most recent consumer survey was in November 2023. The survey results overall were very positive, with consumer satisfaction with service and network reliability remaining high and the rating of our 'friendliness, helpfulness, and consumer concern' remaining high.

The survey results confirm a consistent level of service delivery between the sub-regions of our network.

6.6.1 Price-quality trade-off is changing

96% of consumers surveyed said they were 'very' or 'quite satisfied' with the reliability of the electricity supply. 10% of consumers indicated that they may be prepared to have more interruptions if it means the bill is lower. This is a decrease from 13% in 2022 and 16% in 2021. Of

11 Practice Note, Figure 1, at page 5.
12 Practice Note, Paragraph 81, at page 15.

the 2% who were dissatisfied with the reliability of supply, they were also not prepared to pay more for increased reliability.

The survey results indicate that the tolerance for interruptions is decreasing, and consumer expectations are that interruptions will be few and short. Further, consumers do not necessarily want to pay more for a few interruptions, nor do they want to trade off more interruptions for a lower bill.

Insights into our consumer's service expectations are important to us and form an important part of our pricing strategy and the decisions we make each year when we set out prices.

6.6.2 Uptake of new technologies continues to grow

Our survey indicated that the uptake of new technology remains strong:

- while fewer consumers are considering solar panels, more are considering heat pump ownership.
- the uptake of electric vehicles (or hybrids) continues to show strong growth, and stronger again for commercial users. Hybrid vehicle ownership considerably outnumbers electric vehicle ownership at 80%.
- eBike ownership is likely to increase in the coming year, and electric mobility scooter ownership remains relatively flat.

The responses to our survey question on the uptake of new technology are included in Table 13.

Table 13: Uptake of new technology between pricing years

New Technology uptake	Have			Considering		
	2022	2023	Growth	2022	2023	Growth
Solar Panels	11%	15%	+4%	38%	35%	-3%
Heat Pump(s)	71%	72%	+1%	14%	16%	+2%
Electric or Hybrid[13] Vehicle	13%	17%	+4%	48%	42%	-6%
Charging station[14]	2%	4%	+2%	7%	18%	+11%
eBike	14%	16%	+2%	28%	24%	-4%
Electric Mobility Scooter	3%	5%	+2%	3%	4%	+1%

As consumer's reliance on electricity to manage everyday tasks increases, i.e., using electricity as an energy source to power transport, it is understandable that the tolerance for interruptions is decreasing. Our pricing aims to take account of the uptake in new technologies and consumer's changing expectations in our service delivery.

6.7 CONSUMER IMPACT

Central to an effective price signal is the consumer's understanding and response to the signal that is sent. We send a pricing signal that reflects the forecasted short and long-term demand on our network.

[13] Includes hybrids not requiring electricity to charge.
[14] Respondents require more information before deciding.

Accordingly, the signals we send through our TOU and Day/Night differentials can vary each year to reflect the long-run optimal setting.

Introducing choice has introduced a level of complexity to our pricing. Nevertheless, implementing TOU pricing has introduced appropriate pricing signals and continues to improve our understanding of consumer behaviour. Refining our pricing signals is an ongoing endeavour.

Each year, we assess the impact on consumers of the changes to price structure and price level, taking into account the following:

- the scale of changes to prices for consumers or a consumer group
- whether the price structure is workable for retailers to adopt and apply
- the transaction costs associated with applying the price structure.

The price impact is assessed by examining the average change in price for all consumers. We do not engage directly with consumers; rather, we engage with retailers about how any changes might impact their consumer bills.

Across our network, individuals, households, and whanau face energy hardship in their homes or kāinga. We strive through education, pricing and supporting agencies such as EnergyMate, Levin Budget Services, and Warmer Kiwi Homes to facilitate moving consumers from a position of energy hardship to one of energy well-being. This will be a particularly important part of the next five years as the low fixed charges are phased out.

We recognise that many of our consumers (approximately 80% of all consumers) will be affected by the changes to the low fixed charge regulations. We will continue to work to rebalance the variable proportion of target revenue to mitigate the impact of the increases in fixed charges on low users.

6.7.1 Impact of changes to Low User prices

In line with the low fixed charge regulations, we have increased the fixed daily charge by 15 cents (or +33%). We offset this increase with a decrease in volumetric charges. Resulting in a weighted average increase of $35.10 per annum (or +4%), an increase of approximately 10 cents per day.

The weighted average change in prices by price category for consumers in the low-user category is shown in Table 14.

Table 14: Weighted average change in prices for consumers in the Low User category

Pricing Category	Average Consumption	Estimated No. of ICPs	Weighted Average Increase			
			1 April 2023	1 April 2024	Change p.a.	
General Pricing	5,469	23,672	$914.17	$930.68	+$16.51	+2%
TOU Pricing	6,643	14,671	$892.21	$955.76	+$63.56	+7%
Flexi Pricing	7,476	11	$937.01	$971.40	+$34.40	+4%
Weighted Average	**5,933**	**38,354**	**$940.60**	**$905.50**	**+$35.10**	**+4%**

The impact on individual consumers will depend on which pricing category they have chosen to be in and their consumption profile. Consumers who consume less than 8,000 kWh may be able to reduce their prices by switching to a different price category that better suits their consumption profile. Consumers who are willing and able to shift consumption into the off-peak period could save on their prices by switching from the Uncontrolled/Anytime price category into the TOU Pricing category.

Consumers who consume more than 8,000 kWh per annum are likely to see an increase above the weighted average. We encourage these consumers to consider shifting to the Standard User consumer group.

6.7.2 Impact of changes to Standard User prices

In line with the Authority's expectations, we have increased the proportion of our cost-to-serve from fixed charges and have increased the fixed daily charges by +$0.4323 (or 33%). We have offset this increase with a decrease in volumetric charges. Resulting in a weighted average increase of $9.86 per annum (or +1%), an increase of approximately 2 cents per day, as shown in Table 15.

Table 15: Weighted average change in prices for consumers in the Standard User category

Pricing Category	Average Consumption	Estimated No. of ICPs	Weighted Average Increase			
			1 April 2023	1 April 2024	Change p.a.	
General Pricing	13,083	2,435	$1,723.23	$1,638.49	$(84.74)	-5%
TOU Pricing	10,789	5,424	$1,284.19	$1,320.58	+$36.39	+3%
Flexi Pricing	12,439	5	$1,294.63	$1,267.48	$(27.16)	-2%
Weighted Average	**11,292**	**5**	**$1,380.23**	**$1,390.09**	**+$9.86**	**+1%**

The impact on individual consumers will depend on which pricing category they have chosen to be in and their consumption profile. Consumers who are willing and able to shift consumption into the off-peak period could save on their prices by switching from the Uncontrolled/Anytime price category into the TOU Pricing category.

Because we have increased the fixed charges, consumers who consume 8,000 kWh or less per annum are likely to see an increase above the weighted average. We encourage these consumers to consider shifting to the Low User consumer group.

6.7.3 Impact of changes to Industrial User prices

In line with the Authority's expectations, we have increased the proportion of our cost-to-serve from fixed charges and increased the fixed daily charges by $1.0230 (or 33%). Industrial Users are large and complex consumers. Each has its distinct profile, and accordingly, there is no typical or 'average' consumer by which we can measure the impact of the changes to our prices. To measure consumer impact, we have used a range of consumption profiles, as shown in Table 16.

Table 16: Impacts on Individual Users based on a range of profiles

Profile	Line Charges		Change in Line Charges	
	1 April 2023	1 April 2024	Based on 40,001 kWh per annum	
Off-peak Profile (75% Off-peak/10% Peak/15% Shoulder)	$2,481.53	$2,361.60	$(119.94)	-5%
Managed Profile (50% Off-peak/20% Peak/30% Shoulder)	$2,911.54	$2,892.57	$(18.97)	-1%
Flat Profile (33% Off-peak/33% Peak/33% Shoulder)	$3,264.77	$3,348.63	+$83.87	+3%
Peak Profile (10% Off-peak/70% Peak/20% Shoulder)	$3,939.57	$4,263.50	+$323.93	+8%

Because we have increased the fixed charges, Industrial Users who consume less than 40,000 kWh per annum are likely to have their line charges increase regardless of their profile, and we recommend that they consider shifting to the Standard User consumer group.

6.7.4 There is little to no impact on consumers in the Unmetered and Export groups

The increase in line charges has little or no impact on consumers in the Unmetered and Export consumer groups.

The fixed daily charge for Unmetered connections remains unchanged at $0.15 per day per fitting, and the volumetric charge has increased by +$ 0.0006 (or +0.3%). There is no change to the line charges applied to Export connections; the line charge remains at $0.0000.

6.7.5 We have no control over how (or if) our line charges are passed on to consumers

Our network charges make up approximately 30% of the average consumer's electricity bill. The other 70% comprises transmission, electricity generation, retailer, levies, and GST charges. We do not have a direct relationship with consumers; instead, we bill the electricity retailers for our services, and the retailers pass our lines charge through to their customers. Accordingly, we have no control over how retailers pass our network charges on to consumers. Questions about how the changes to our network charges will affect an individual consumer's total electricity bill are better directed to consumers' electricity retailers.

Electricity retailing is a competitive market, and this allows consumers to choose which electricity retailer they buy their electricity from. Consumers' total electricity bills can vary depending on which retailer that consumer is with and what plan they are on. We do not offer advice to consumers about their electricity bills. Consumers can get electricity price comparisons through Powerswitch, run by Consumer NZ. Powerswitch is a free, independent service that helps consumers determine the cheapest pricing plan.

More information on switching retailers can be found at: www.powerswitch.org.nz

Calculation of Our Costs to Serve

7.1 CALCULATION OF OUR COSTS TO SERVE

The Required Revenue represents the forecasted costs to serve in the provision of electricity distribution line services. Through our prices, effective 1 April 2024, we intend to recover our Required Revenue of **$59,109,128**. Table 17 provides a breakdown of our Required Revenue for the pricing year.

Table 17: Calculation of Required Revenue for the pricing year

Description	Amount
Operating Expenditure	$22,816,043
Depreciation	$18,101,475
Regulatory Tax Allowance	$1,750,111
Revaluations	$(5,775,670)
Return on Investment (incl. Sales Discount)	$12,026,067
Transmission	$9,810,918
Rates & Levies	$380,183
Total Required revenue	**$59,109,128**

7.2 CALCULATION OF THE OPERATING EXPENDITURE

Our forecast Operating Expenditure for the pricing year is **$22,816,043**. Table 18 provides a breakdown of our forecast Operating Expenditure Costs for the pricing year.

Table 18: Forecast Operating Expenditure for the pricing year

Description	Amount
Service Interruptions and Emergencies	$2,406,695
Vegetation Management	$2,009,330
Routine and Corrective Maintenance	$2,348,924
Asset Replacement and Renewal	$604,090
System Operations and Network Support	$7,279,134
Business Support	$7,887,870
Shared Benefit Mangahao embedded generation (ACOD)	$280,000
Total Operations & Maintenance Costs	**$22,816,043**

7.2.1 Calculation of the Depreciation Charges

Our forecast Depreciation Charges for the pricing year are **$18,101,475**. The Depreciation Charges reflect the annual charge to the accounts for depreciation on network system assets and related fixed assets such as communications equipment and network-related software. Per the company's management accounts, our forecast equals the budgeted depreciation charges for the Network business unit between 1 April 2024 and 31 March 2025.

Table 19 summarises our budgeted Depreciated Charges for the pricing year.

Table 19: Forecast Depreciation Charges for the pricing year

Description	Amount
Depreciation—Network Assets	$16,490,452
Depreciation—non-network Assets	$1,611,023
Total Depreciation Charges	**$18,101,475**

7.2.2 Calculation of the Cost of Capital

Our forecast Cost of Capital calculations for the pricing year are **$8,000,509**. Table 20 summarises our forecast Cost of Capital Charges for the pricing year.

Table 20: Forecast Cost of Capital for the pricing year

Description	Amount
Regulatory Tax Allowance	$1,750,111
Revaluations	$(5,775,670)
Return on Investment	$12,026,067
Total Cost of Capital Charges	**$8,000,509**

7.2.3 Calculation of the Electra Trust Divided and Consumer Discount

This pricing year, we will pay the Electra Trust a dividend of $383,548 to meet the Trust's operating costs.

Additionally, we will distribute approximately $5,398,099 of the network discount[15] via a fixed amount of $50 per ICP (or $0.1370 per day for the number of days the ICPs is electrically connected) and the remaining applied as a discount on electricity consumption at $0.0059 per kWh.

The discount is applied to all 'qualifying customers' as of 31 January 2025. To be eligible for the discount, consumers must be the retail electricity account holder of the active connection on 31 January 2025.

More information about the distribution of the network discount can be found in the Electra Limited Statement of Intention to Pay Discount, which is available on our website.

7.2.4 Calculation of the Transmission Charges

Our forecast Transmission Charges for the pricing year are **$9,810,918**. The Transmission Charges reflect the notified charges from Transpower we receive in early December each year. We pass these charges through to consumers through prices each year.

Table 21 summarises our forecast Transmission Charges for the pricing year.

[15] It is our intention to provide consumers with an annual discount consistent with the target published in our Statement of Corporate Intent. Therefore, a final adjustment may be made to ensure the payment aligns with the published target.

Table 21: Forecast Transmission Charges for the pricing year

Description	Amount
Connection Charge	$1,700,498
Benefit-based charges (BBC)	$1,303,987
Residual Charge	$6,125,496
Transitional Cap	$5,932
New investment charges	$675,004
Avoided cost of transmission (ACOT)	-
Total Transmission Charges	**$9,810,918**

7.2.5 Calculation of the Rates & Levies

Our forecast Rates & Levies cost recovery for the pricing year are **$380,183**. Table 22 summarises the forecast Rates & Levies Charges for the pricing year.

Table 22: Forecast Rates & Levies recovery for the pricing year

Description	Amount
Council Rates	$184,370
Commerce Act Levies	$31,930
Electricity Authority Levies	$87,663
Utilities Disputes Levies	$28,840
FENZ Levies	$47,380
Total Rates & Levies Charges	**$380,183**

7.3 CHANGE IN REQUIRED REVENUE

Our Required Revenue has increased by +**$5,373,557** (or +10%) for the 1 April 2024 pricing year compared to the 1 April 2023 pricing year. Table 23 provides the movement in Required Revenue between the pricing years.

Table 23: Movement in Revenue Requirement between pricing years

Description	1 April 2023	1 April 2024	Movement	
Operating Expenditure	$20,000,000	$22,816,043	+$2,816,043	+14%
Depreciation	$14,900,000	$18,101,475	+$3,201,475	+21%
Regulatory Tax Allowance	$1,877,531	$1,750,111	$(127,420)	-7%
Revaluations	$(7,550,000)	$(5,775,670)	+$1,774,330	-24%
Return on Investment	$14,255,469	$12,026,067	$(2,229,401)	-16%
Transmission	$9,883,425	$9,810,918	$(72,507)	-1%
Rates & Levies	$369,146	$380,183	+$11,037	+3%
Total Required Revenue	**$53,735,571**	**$59,109,128**	**$5,373,557**	**+10%**

7.3.1 Change in Operations & Maintenance Costs

We have forecast an increase in Operations Expenditure of +**$2,816,043** (or +14%) for the pricing year driven by increases in the direct costs of labour and materials. Table 24 compare Operations & Maintenance Costs expenditure between pricing years.

Table 24: Comparison of Operations Expenditure between pricing years

Description	1 April 2023	1 April 2024	Movement	
Service Interruptions and Emergencies	$2,395,025	$2,406,695	+$11,670	+0.5%
Vegetation Management	$1,954,397	$2,009,330	+$54,933	+3%
Routine and Corrective Maintenance	$1,569,440	$2,348,924	+$779,484	+50%
Asset Replacement and Renewal	$600,533	$604,090	+$3,557	+1%
System Operations and Network Support	$6,223,275	$7,279,134	+$1,055,859	+17%
Business Support	$7,257,329	$7,887,870	+$630,541	+9%
Shared Benefit Mangahao embedded generation (ACOD)[16]	-	$280,000	+$280,000	+100%
Total Operations Expenditure	**$20,000,000**	**$22,816,043**	**+$2,816,043**	**+14%**

The Increase in operational expenditure is largely driven by inflationary pressures as the cost of labour and materials has increased significantly over the last three years, driven by unusually high CPI and the continuing disruption of international supply chains.

7.3.2 Change in Depreciation Charges

We have forecasted an increase in depreciation charges of +**$3,201,475** (or +21%). Table 25 compares Depreciation Charges between years.

Table 25: Comparison of Depreciation Charges between pricing years

Description	1 April 2023	1 April 2024	Movement	
Depreciation - Network Assets	$12,591,803	$16,490,452	+$3,898,649	+31%
Depreciation - Non-network Assets	$2,308,197	$1,611,023	$(697,174)	-30%
Total Depreciation Charges	**$14,900,000**	**$18,101,475**	**+$3,201,475**	**+21%**

The +21% increase in Depreciation Charges reflects the increasing value of our electricity network assets, which are subject to annual accounting revaluation.

[16] In past pricing years, we have treated the shared benefit from Mangahao embedded generation as a transmission benefit. This pricing year, we have changed the treatment to be a avoided cost of transmission to align with the Electricity Authority's expectation that transmission charges are reflective of the notified transmission costs from Transpower New Zealand under the Transmission Pricing Methodology (TPM).

7.3.3 Change in Cost of Capital

We have forecasted a decrease in the Cost of Capital of **$(582,491)** (or -7%). Table 26 compares the Cost of Capital between years.

Table 26: Comparison of Cost of Capital between pricing years

Description	1 April 2023	1 April 2024	Movement	
Regulatory Tax Allowance	$1,877,531	$1,750,111	$(127,420)	-7%
Revaluations	$(7,550,000)	$(5,775,670)	+$1,774,330	-24%
Return on Investment	$14,255,469	$12,026,067	$(2,229,401)	-16%
Total Operations Expenditure	**$8,583,000**	**$8,000,509**	**$(582,491)**	**-7%**

The -7% decrease in Cost of Capital is driven by a forecast change in CPI of -2.75% for this pricing year. The 2023 March quarter saw a 10-year high in CPI at 6.65%[17]. The change to the CPI drives the Revaluations and Return on Investment.

For this pricing year, we have forecast CPI using NZIER's forecast of 3.9% for the 2024 March quarter and 2.4% for the 2025 March quarter[18]. Accordingly, as CPI is forecast to reduce, we are forecasting a $1,774,330 (or -24%) reduction in the Revaluations for this pricing year and $(2,229,401) (or -16%) in the Return on Investment.

7.3.4 Change in Transmission Charges

We have forecasted a decrease in transmission charges of **$(72,507)** (or -1%). Table 27 compares transmission charges between pricing years.

Table 27: Comparison of Transmission Charges between pricing years

Description	1 April 2023	1 April 2024	Movement	
Settlement Residue Allocation Methodology (SRAM)	$(1,260,614)	-	$1,260,614	-100%
Connection Charge	$1,651,524	$1,700,498	$48,974	+3%
Benefit-based charges (BBC)	$1,250,234	$1,303,987	$53,753	+4%
Residual Charge	$5,944,260	$6,125,496	$181,236	+3%
Transitional Cap	$27,237	$5,932	$(21,305)	-78%
New investment charges	$674,284	$675,004	$720	0.1%
Avoided cost of transmission (ACOT)	-	-	-	-
Shared Benefit Mangahao embedded generation (ACOD)	$1,596,500	-	$(1,596,500)	-100%
Total Operations Expenditure	**$9,883,425**	**$9,810,918**	**$(72,507)**	**-1%**

[17] Consumer price index: March 2023 quarter can be found on the Stats NZ, Tauranga Aotearoa website.
[18] New Zealand Institute of Economic Research (NZIER), Consensus Forecasts, Media Release 12 June 2023.

Transpower sets its prices under the Transmission Pricing Methodology (TPM). We pass through the transmission charges from Transpower to consumers. Transpower sets its prices per the TPM administered by the Authority. More information on the TPM can be found on the Authority's website[19].

The -1% decrease in transmission costs is due to the 3% increase in Transpower's notified transmission charges effective 1 April 2024 being offset by our decision for this pricing year to:

- change the treatment of the shared benefit derived from the Mangahao embedded generation; and
- return the SRAM directly to retailers for this pricing year and not through prices, as was the case for the prior pricing year.

Historically, we have treated the payments we make to Mangahao embedded generation as an avoided cost of transmission (ACOT). In April 2023, the new TPM took effect, and the Authority made clear its expectations that transmission charges would only have regard for charges directly incurred from Transpower. We have amended our internal treatment of the shared benefit derived from the Mangahao embedded generation from an ACOT to an avoided cost or distribution (ACOD).

The SRAM came into effect on 1 April 2023, requiring distributors to allocate the settlement residue paid by Transpower in proportion to each connection location. The Authority did not release guidance as to how distributors should administer the SRAM until May 2023; accordingly, for 1 April 2023, we chose to return the SRAM through prices by reducing transmission charges by $1,260,614, as shown in Table 27. This pricing year, we have chosen to change our approach and will pay the SRAM directly to retailers each month, as per the Authority's guidelines and expectations. Retailers should return the SRAM paid to consumers. However, there is no mandate for them to do so.[20]

7.3.5 Change in Rates & Levies Recovery

We have forecasted an increase in rates and levies of +**$11,037** (or +3%). Table 28 compares rates and levies recovery between pricing years.

Table 28: Comparison of Rates & Levies between pricing years

Description	1 April 2023	1 April 2024	Movement	
Council Rates	$179,000	$184,370	+$5,370	+3%
Commerce Act Levies	$31,000	$31,930	+$930	+3%
Electricity Authority Levies	$85,146	$87,663	+$2,517	+3%
Utilities Disputes Levies	$28,000	$28,840	+$840	+3%
FENZ Levies	$46,000	$47,380	+$1,380	+3%
Total Operations Expenditure	**$369,146**	**$380,183**	**+$11,037**	**+3%**

19 www.ea.govt.nz/operations/transmission/transmission-pricing
20 A copy of the Electra, Settlement Residue Payments Methodology, Effective from 1 April 2024 can be found on our website.

The +3% increase in rates and levies is driven by a forecast uplift in CPI of 3%. We have chosen a conservative change of 3% as while any one rate or levy can change by more than 3%, total rates and levies tend to track close to forecast CPI.

7.4 RECOVERY OF REQUIRED REVENUE FROM CONSUMER GROUPS

We recover our Required Revenue from consumers through prices. Table 29 shows the Required Revenue by Consumer Group for the pricing year.

Table 29: Required Revenue by Consumer Group for the pricing year

Consumer Group	Required Revenue	Proportion of Required Revenue
Low Users (<= 8,000 kWh per year)	$41,412,929	70%
Standard Users (>8,000 kWh per year)	$10,773,193	18%
Industrial (>40,000 kWh per year)	$5,979,411	10%
Unmetered	$943,595	2%
Export	-	-
Total	**$59,109,128**	**100%**

As discussed in Section 3, our pricing strategy aims to set efficient and appropriate prices. When setting prices, we do so with the objectives of fairness, distributing the agreed discount to consumers, sending price signals to consumers, avoiding bill shock, and aligning with the Authority's Pricing Principles. We set prices to recover the total Required Revenue over the pricing year to meet our aims and objectives.

Our Approach to Setting Prices

8.1 OUR APPROACH TO SETTING PRICES

To set prices, we use a bottom-up approach that includes two steps:

Step 1 — the cost of supply model (CoSM) allocates the Revenue Requirement to the following:

- two grid exit points (GXP) that the Electra network connects to, Mangahao and Paraparaumu
- five Consumer Groups (Low Users, Standard Users, Industrial, Unmetered, and Export).

Step 2 — the pricing design model sets the Target Revenue by:

- setting distribution, pass-through & recoverable, and transmission prices by GXP within each Consumer Group based on fixed and variable charges
- rolling the distribution, pass-through & recoverable, and transmission prices at each GXP up to set uniform delivery charges.

8.2 OVERVIEW OF OUR APPROACH TO ALLOCATING THE REVENUE REQUIREMENT

8.2.1 First, we allocate the Required Revenue to the GXPs

The CoSM first allocates our Revenue Requirement across the two GXPs that the Electra network connects to, Mangahao and Paraparaumu, based on the principal driver of the cost components of the Required Revenue. We use eight drivers of cost at each GXP:

- Number of ICPs
- Total Consumption
- Installed Capacity
- Asset Utilisation
- Line Length
- Value of the Regulatory Asset Base (RAB)
- RAB Depreciation.
- Attributable Costs

The allocation to each GXP by cost driver is shown in Table 30.

Table 30: Allocation to GXP by cost driver for the pricing year

Description	Mangahao	Paraparaumu
No. of ICPs	38%	62%
Consumption	41%	59%
Installed capacity	39%	61%
Asset Utilisation	39%	61%
Line Length	29%	71%
Regulated Asset Base	41%	59%
Regulated Asset Base - Depreciation	41%	59%

The allocation of our Revenue Requirement to each GXP by cost component and cost driver is shown in Appendix D — Delivery charges effective 1 April .

8.2.2 Next, we allocate the Revenue Requirement at the GXP to consumer groups

Using the allocated Required Revenue by GXP, the CoSM next allocates the Revenue Requirement by GXP to the Consumer Groups, again based on the driver of the cost to serve each Consumer Group. We use four drivers to allocate costs to the consumer groups:

- Number of ICPs
- Total Consumption
- Installed Capacity
- Asset Utilisation

The allocation to the Consumer Group by cost driver for the Mangahao GXP is shown in Table 31.

Table 31: Allocation to the Consumer Group at the Mangahao GXP for the pricing year

Description	Low User	Standard User	Industrial	Unmetered	Export
No. of ICPs	80%	18%	1%	1%	-
Consumption	54%	18%	28%	0.2%	-
Installed capacity	79%	14%	4%	3%	-
Asset Utilisation	79%	14%	4%	3%	-

The allocation to the Consumer Group by cost driver for the Paraparaumu GXP is shown in Table 32.

Table 32: Allocation to the Consumer Group at the Paraparaumu GXP for the pricing year

Description	Low User	Standard User	Industrial	Unmetered	Export
No. of ICPs	77%	22%	0.5%	1%	-
Consumption	60%	24%	16%	0.4%	-
Installed capacity	78%	17%	3%	2%	-
Asset Utilisation	78%	17%	3%	2%	-

We allocate costs based on our historical quantities using information from our billing system, EIEP files provided by traders, and our year-end information disclosure schedules. Table 33 provides the quantities used to allocate the Required Revenue to the Mangahao GXP for the pricing year.

8.3 WE USE HISTORICAL QUANTITIES TO ALLOCATE THE REQUIRED REVENUE

Table 33: Quantities used to allocate Required Revenue to the Mangahao GXP for the pricing year

Consumer Group	No. of ICPs	Consumption (kWh)	Installed Capacity (kVA)	Asset Utilisation (kW)	Line Length (km)	RAB	RAB Depreciation
Low Users	14,502	93,918,368	94,263	86,296			
Standard Users	3,318	31,535,321	16,590	15,188			
Industrial	139	48,426,111	5,004	4,581			
Unmetered	182	358,989	3,458	3,166			
Export	-	-	-	-			
Total Quantities	**18,141**	**174,238,790**	**119,315**	**109,231**			
Conductor LV Cable					200		
Conductor LV Over Head					370		
Conductor HV Cable					9		
Conductor HV Over Head					86		
Total Line Length					**665**		
Sub-transmission lines						$4,249,033	$179,627
Sub-transmission cables						$5,237,634	$132,269
Zone substations						$12,863,365	$527,387
Distribution and LV lines						$23,352,501	$855,890
Distribution and LV cables						$16,509,210	$532,960
Distribution substations and transformers						$12,297,661	$427,637
Distribution switchgear						$7,432,489	$276,810
Other network assets						$5,954,537	$497,456
Non-network assets						$5,548,970	$834,524
Total Regulated Asset Base						**$93,445,400**	**$4,264,561**

Table 34 provides the quantities allocated to the Required Revenue at the Paraparaumu GXP for the pricing year.

Table 34: Quantities used to allocate Required Revenue to the Paraparaumu GXP for the pricing year

Consumer Group	No. of ICPs	Consumption (kWh)	Installed Capacity (kVA)	Asset Utilisation (kW)	Line Length	RAB	RAB Depreciation
Low Users	22,253	148,229,755	144,645	132,420			
Standard Users	6,427	59,865,565	32,135	29,419			
Industrial	144	39,665,859	5,184	4,746			
Unmetered	210	931,162	3,990	3,653			
Export	-	-	-	-			
Total Quantities	**29,034**	**248,692,341**	**185,954**	**170,238**			
Conductor LV Cable					544		
Conductor LV Over Head					1,000		
Conductor HV Cable					22		
Conductor HV Over Head					100		
Total Line Length					**1,666**		
Sub-transmission lines						$6,064,678	$256,383
Sub-transmission cables						$7,475,715	$188,789
Zone substations						$18,359,977	$752,744
Distribution and LV lines						$33,331,200	$1,221,618
Distribution and LV cables						$23,563,721	$760,698
Distribution substations and transformers						$17,552,545	$610,369
Distribution switchgear						$10,608,448	$395,094
Other network assets						$8,498,955	$710,023
Non-network assets						$7,920,086	$1,191,122
Total Regulated Asset Base						**$133,375,325**	**$6,086,839**

8.4 OVERVIEW OF OUR APPROACH TO SETTING TARGET REVENUE

The pricing design model sets our prices from which we will recover our Target Revenue for each consumer group over the pricing year. The pricing design model first sets distribution and transmission prices for each consumer group by GXP and then a uniform delivery charge.

8.4.1 First, we determine the fixed / variable split

The first step to setting delivery charges is determining each consumer group's fixed / variable split. Our transition to use-based pricing will increase the fixed component and decrease the variable year-on-year over the next five years. Table 35 compares the fixed and variable spilt applied in this pricing year to the prior pricing year.

We intend to transition to our ideal fixed vs variable split of 70% fixed / 30% variable over the next five years.

More discussion on the evolution of our prices can be found in Section 4.

Table 35: Comparison of the fixed/variable split between pricing years

Consumer Group		1 April 2023		1 April 2024		Change	
		Fixed	Variable	Fixed	Variable	Fixed	Variable
Low Users	General Pricing	16%	84%	20%	80%	+4%	-4%
	TOU Pricing	24%	76%	21%	79%	-3%	+3%
	Flexi Pricing	28%	72%	30%	70%	+2%	-2%
Standard Users	General Pricing	62%	38%	48%	52%	-15%	+15%
	TOU Pricing	44%	56%	46%	54%	+2%	-2%
	Flexi Pricing	59%	41%	62%	38%	+4%	-4%
Industrial		3%	97%	7%	93%	+4%	-4%
Unmetered		97%	3%	83%	17%	-15%	+15%
Export		-	-	-	-	-	-

8.4.2 Next, we set the fixed and variable prices

Next, we set the fixed and variable prices within each consumer group by using the following formula:

((CoSM allocated Required Revenue x split) x allocation to price / quantities)

Table 36 shows the allocation of variable prices to Uncontrolled/Anytime and Time-of-Use price categories for the pricing year.

Table 36: Prices differential for variable prices in each Price Category for the pricing year

Consumer Group		Uncontrolled/ Anytime	Time of Use				
			Day	Night	Off-peak	Peak	Shoulder
Low Users	General Pricing	100%	70%	30%			
	TOU Pricing				18%	48%	34%
	Flexi Pricing				18%	45%	37%
Standard Users	General Pricing	100%	11%	89%			
	TOU Pricing				5%	61%	34%
	Flexi Pricing				4%	56%	40%
Industrial					6%	61%	33%
Unmetered		100%					
Export		NA					

Table 37 shows the breakdown of Target Revenue recovered through fixed and variable revenue.

Table 37: Breakdown of Target Revenue recovered through fixed and variable revenue

Consumer Group	Pricing Category	Fixed Revenue	Variable Revenue	Total Revenue
Low Users	General Pricing	$5,184,168	$20,745,562	$25,929,730
	TOU Pricing	$3,212,949	$12,262,233	$15,475,182
	Flexi Pricing[21]	$2,409	$5,608	$8,017
Standard Users	General Pricing	$1,548,537	$1,705,082	$3,253,619
	TOU Pricing	$3,449,362	$4,065,116	$7,514,478
	Flexi Pricing[22]	$3,180	$1,917	$5,121
Industrial		$428,895	$5,550,516	$5,979,411
Unmetered		$780,168	$163,427	$943,595
Export		-	-	-
Total Revenue		**$14,609,667**	**$44,499,461**	**$59,109,128**

8.4.3 We smooth prices to avoid bill shock

We use the allocation to variable prices to smooth end prices so we can:

- meet our regulatory requirements (e.g., low fixed charge regulations) by capping fixed daily charges for domestic consumers
- recover our Required Revenue
- avoid bill shock to consumers as we evolve our prices to be more cost-reflective.

21 Low User, Flexi Pricing makes up 0.01% of the Total Required Revenue.
22 Standard User, Flexi Pricing makes up 0.01% of the Total Required Revenue.

We use a three-step process to smooth variable prices:

Step 1: set the initial allocations based on the future pricing strategy

Step 2: adjust prices to comply with the low fixed charge regulations

Step 3: spread the under-recovered revenue from applying the low fixed charge regulation across the commercial and industrial consumers in a fair manner and avoid bill shock to the consumers in those consumer groups.

8.4.4 We use forecast year-end quantities to set prices

We use year-end forecast quantities when setting our prices. Quantities are forecast for each consumer group based on the prior year's quantities multiplied by a growth factor. Quantities used to set prices include:

- Number of ICPs
- Consumption in kWh:
  - Uncontrolled Anytime, or
  - Time of use - Day/Night, or
  - Time of use - Off-peak/Peak/Shoulder.

Table 38 provides the forecast quantities for the pricing year.

Table 38: Forecast quantities used to set prices for the pricing year

Consumer Group	Pricing Category	Number of ICPs	Consumption (kWh)
Low Users	General Pricing	23,672	171,127,168
	TOU Pricing	14,671	113,632,160
	Flexi Pricing	11	57,233
Standard Users	General Pricing	2,435	22,559,853
	TOU Pricing	5,424	63,288,711
	Felix Pricing	5	37,444
Industrial		285	109,811,063
Unmetered		-	1,089,513
Total		**46,503**	**481,603,144**

8.4.5 Target Revenue is derived by multiplying prices by forecast quantities

The target revenue for each consumer group is set by using the following formula:

Price x Forecast quantities = Target Revenue

Table 39 provides a breakdown of the Target Revenue by Consumer Group and the proportion of the revenue from each Consumer Group of Target Revenue for the pricing year.

Table 39: Target Revenue by Consumer Group for the pricing year

Consumer Group	Pricing Category	Target Revenue	Proportion
Low Users	General Pricing	25,929,730	44%
	TOU Pricing	15,475,182	26%
	Flexi Pricing[23]	8,017	0%
Standard Users	General Pricing	3,253,619	6%
	TOU Pricing	7,514,478	13%
	Flexi Pricing[24]	5,096	0%
Industrial		5,979,411	10%
Unmetered		943,595	2%
Export		-	-
Total		**59,109,128**	**100%**

A breakdown of Target Revenue by disclosed prices multiplied by quantities is available in Appendix E — Breakdown of the Required Revenue by GXP and Consumer Group.

8.5 CHANGE IN TARGET REVENUE

Target Revenue has increased by **+$5,373,557** (or +10%) for this pricing year. Table 40 shows Target Revenue's movements within consumer groups between pricing years.

Table 40: Movement in Target Revenue by consumer group between pricing years

Consumer Group	Pricing Category	1 April 2023	1 April 2024	Movement	
Low Users	General Pricing	23,154,133	25,929,730	+2,775,597	+12%
	TOU Pricing	14,034,245	15,475,182	+1,440,938	+10%
	Flexi Pricing	7,133	8,017	+883	+12%
Standard Users	General Pricing	2,957,566	3,253,595	+326,054	+11%
	TOU Pricing	6,851,269	7,514,478	+663,208	+10%
	Flexi Pricing	4,457	5,121	+639	+14%
Industrial		5,828,135	5,979,411	+151,276	+3%
Unmetered		928,632	943,595	+14,962	+2%
Export		-	-	-	-
Total Revenue		**53,735,571**	**59,109,128**	**+5,373,557**	**+10%**

23 Low User, Flexi Pricing makes up 0.01% of the Total Required Revenue.
24 Standard User, Flexi Pricing makes up 0.01% of the Total Required Revenue.

Table 41 compares the Revenue Requirement and Target Revenue by Consumer Group for the pricing year.

Table 41: Comparison of Required Revenue and Target Revenue by Consumer Group

Consumer Group	Required Revenue	Target Revenue	Variance	
Low Users (<= 8,000 kWh per year)	$41,412,929	$41,412,929	-	-
Standard Users (>8,000 kWh per year)	$10,773,193	$10,773,193	-	-
Industrial (>40,000 kWh per year)	$5,979,411	$5,979,411	-	-
Unmetered	$943,595	$943,595	-	-
Export	-	-	-	-
Total	**$59,109,128**	**$59,109,128**	**-**	**-**

We Value Your Comments....

We welcome your feedback on this Pricing Methodology and appreciate your taking the time to provide us with your comments, compliments, and complaints. We can be contacted on 0800 Electra (0800 353 2872) during normal business hours or through the Contact Form at any time.

9.1 OUR COMPLAINTS PROCESS

Our consumers have the right to always expect quality service and support from us. If you have a complaint or problem, including land issues, we want to know so that we can fix it.

A quick chat with a staff member at Electra is often all that is required to resolve your concern. Call us on 0800 Electra (0800 353 2872) between 8am – 5pm on weekdays and ask to speak with our Customer Experience Manager. They will take personal responsibility for ensuring your complaint is thoroughly investigated and resolved as quickly and equitably. We endeavour to resolve all formal complaints within a period of 20 days, and there is no charge for this service.

UTILITIES DISPUTES
TAUTOHETOHE WHAIPAINGA

If we do not resolve your complaint to your satisfaction, you can contact Utilities Disputes at 0800 22 33 40 or go to www.utilitiesdisputes.co.nz. We are a member of the Utilities Disputes Scheme, a free and independent service for resolving complaints about utilities providers.

Appendices

Appendix A – Alignment with the Information Disclosure Requirements

Table 42 references where, in this Pricing Methodology, we have provided the information required by the Commerce Commission in its Electricity Distribution Information Disclosure Determination 2012 (the ID Determination).

Table 42: Information Disclosure Requirements Compliance Matrix

Information Disclosure Requirement	ID Determination Reference	Pricing Methodology Reference
Every EDB must publicly disclose, before the start of each disclosure year, a pricing methodology which—	Clause 2.4.1	
(1) Describes the methodology, in accordance with clause 2.4.3, used to calculate the prices payable or to be payable;	Clause 2.4.3	Section 7 Section 8 Section 8.2
(2) Describes any changes in prices and target revenues;		Section 7.3 Section 8.5
(3) Explains, in accordance with clause 2.4.5, the approach taken with respect to pricing in non-standard contracts and distributed generation (if any);	Clause 2.4.5	Section 5.10.2 Section 5.9
(4) Explains whether, and if so, how, the EDB has sought the views of consumers, including their expectations in terms of price and quality, and reflected those views in calculating the prices payable or to be payable. If the EDB has not sought the views of consumers, the reasons for not doing so must be disclosed.		Section 5.11 Section 6.6
Any change in the pricing methodology or adoption of a different pricing methodology, must be publicly disclosed at least 20 working days before prices determined in accordance with the change of different pricing methodology take effect.	Clause 2.4.2	NA — there were no changes in pricing methodology, nor did we adopt a different pricing methodology.

Information Disclosure Requirement	ID Determination Reference	Pricing Methodology Reference
Every disclosure under clause 2.4.1 above must—	Clause 2.4.3	
(1) Include sufficient information and commentary to enable interested persons to understand how prices were set for each consumer group, including the assumptions and statistics used to determine prices for each consumer group;		Section 5
(2) Demonstrate the extent to which the pricing methodology is consistent with the pricing principles and explain the reasons for any inconsistency between the pricing methodology and the pricing principles;		Appendix B
(3) State the target revenue expected to be collected for the disclosure year to which the pricing methodology applies;		Section 8.4 Appendix F
(4) Where applicable, identify the key tariffs of target revenue required to cover the costs and return on investment associated with the EDBs provision of electricity lines services. Disclosure must include the numerical value of each of the tariffs;		Section 8.5 Table 40 Appendix E Appendix F
(5) State the consumer groups for whom prices have been set, and describe:		Section 5.2 Appendix C
(a) the rationale for grouping consumers in this way;		Sections 5.5 to 5.9
(b) the method and criteria used by the EDB to allocate consumers to each of the consumer groups;		Sections 5.3 and 5.4
(6) If prices have changed from prices disclosed for the immediately preceding disclosure year, explain the reasons for change, and quantify the difference in respect of each of those reasons;		Section 6 Section 6.4 Section 6.7 Section 7.3 Appendix D

Information Disclosure Requirement	ID Determination Reference	Pricing Methodology Reference
(7) Where applicable, describe the method used by the EDB to allocate the target revenue among consumer groups, including the numerical values of the target revenue allocated to each consumer group, and the rationale for allocating it in this way;		Section 7 Table 29 Section 8 Table 39 Appendix E
(8) State the proportion of target revenue (if applicable) that is collected through each price tariff as publicly disclosed under clause 2.4.18;		Table 29 Table 39 Appendix F
Every disclosure under clause 2.4.1 above must, if the EDB has a pricing strategy—	Clause 2.4.4	
(1) Explain the pricing strategy for the next 5 disclosure years (or as close to 5 years as the pricing strategy allows), including the current disclosure year for which prices are set;		Section 3 Figure 1
(2) Explain how and why prices for each consumer group are expected to change as a result of the pricing strategy;		Sections 6.1 to 6.3
(3) If the pricing strategy has changed from the preceding disclosure year, identify the changes and explain the reasons for the changes;		Section 6.4 Section 6.7
Every disclosure under clause 2.4.1 above must:	Clause 2.4.5	

Information Disclosure Requirement	ID Determination Reference	Pricing Methodology Reference
(1) Describe the approach to setting prices for non-standard contracts, including:		
(a) the extent of non-standard contract use, including the number of ICPs represented by non-standard contracts and the value of target revenues expected to be collected from consumers subject to non-standard contracts;		Section 5.4
(b) how the EDB determines whether to use a non-standard contract, including any criteria used;		Section 5.4
(c) any specific criteria or methodology used for determining prices for consumers subject to non-standard contracts and the extent to which these criteria or that methodology are consistent with the pricing principles;		NA – Electra do not currently have any consumers on non-standard contracts.
(2) Describe the EDB's obligations and responsibilities (if any) to consumers subject to non-standard contracts in the event that the supply of electricity lines services to the consumer is interrupted. This description must explain: (a) the extent of the differences in the relevant terms between standard contracts and non-standard contracts;		
(b) any implications of this approach for determining prices for consumers subject to non-standard contracts;		
(3) Describe the EDBs approach to developing prices for electricity distribution services provided to consumers that own distributed generation, including any payments made by the EDB to the owner of any distributed generation, and including the: (a) Prices; and (b) Value, structure and rationale for any payments to the owner of the distributed generation.		Subsection 7.2.3

As clause 2.9.1 of the Determination requires, Director certification can be found in Appendix G — Director Certification for the Year-beginning Disclosures.

Appendix B – Consistency with the Electricity Authority Pricing Principles

In October 2022, the Authority released its Second Edition 2.2, 2022, Practice Note updated[25] to:

> '*provide further guidance to assist distributors with applying the 2019 Distribution Pricing Principles.*'[26]

The Practice Note provides context for the Authority's Pricing Principles, including that for each of the four principles, prices should:

- signal the economic costs of service provision
- recover residual costs in a manner that least distorts network use
- respond to end users' economic value of services and price/quality trade-offs
- develop in a transparent manner having regard for impacts on consumers.

We have reviewed our pricing for consistency with the Authority's 2019 Pricing Principles. In the following sections, we provide our interpretation of each principle, an assessment of how our current prices is consistent with the principle, and how we intend to improve as we implement and execute our five-year pricing strategy.

Principle A: Prices are to signal the economic cost of service provision, including by:

i. Being subsidy free (equal to or greater than avoidable costs, and less than or equal to standalone costs)

Our interpretation

We have interpreted this principle to mean prices are economically efficient where the charges recovered from each consumer group fall within the subsidy-free range established by standalone cost and avoidable cost.

- Standalone costs — reflect the costs a consumer would face to supply their energy needs from alternative energy sources.
- Avoidable costs — are the future cash costs the network avoids if a consumer group were to disconnect from the network.

We consider prices are only likely to fall below avoidable costs for consumers with very low levels of annual consumption. This is partly due to the impact of low fixed charge regulations, which limits the recovery of cost-reflective charges from domestic consumers with low annual consumption. With the phasing out of restrictions beginning on 1 April 2022, we believe this will alleviate any potential cross-subsidy as fixed charges will exceed avoided costs.

25 The first Practice Note is Electricity Authority, Distribution Pricing: Practice Note August 2019.

26 Electricity Authority, Distribution Pricing: Practice Note, Second Edition 2.2, 2022, October 2022 (the Practice Note), paragraph 1 on page 2.

Our pricing approach is to allocate costs between consumer groups using cost-reflective allocators. This results in allocations that fall between stand-alone costs and avoided costs on average on the basis that the cost allocators used represent the underlying network cost drivers.

Standalone cost

Prices above standalone costs cannot be sustained over time as competing energy sources will encourage consumers to bypass the network. Consumers would be better off disconnecting from the electricity network and taking up the alternative energy solution where total electricity charges exceed standalone costs. This outcome is inefficient as charges for the remaining consumers would need to increase, which may potentially distort network usage.

While the cost of solar is decreasing, obtaining the equivalent security and quality of supply adds significant cost (e.g., diesel generation) and generally makes going off-grid uneconomic. Supply from the network, by comparison, has economies of scale as costs are spread across consumers. As an example, residential consumers considering connecting within 1km of our existing network will likely find the network connection option to be cheaper than a stand-alone power system.

For larger connections, standalone costs may depend on the location of the consumer relative to the connection to the transmission grid (the GXP). We estimate a constant load greater than 5MW and closer than 2km to a GXP would be required to make bypass cheaper than our existing prices. The annualised cost of this would be in the order of $100,000.

Rural/urban cross-subsidy

A cross-subsidy could potentially arise from not explicitly recognising circuit length as a cost driver in prices. The only discernible cross-subsidy likely to arise in relation to circuit length is between rural and urban consumers, as rural consumers have a longer circuit length than urban consumers, and there is higher connection density in urban areas, leading to urban consumers subsidising rural consumers.

We do not consider disaggregating rural and urban consumers for pricing purposes to be beneficial.

- Rural circuits, poles, and equipment are also used by urban consumers as electricity may flow through sub-transmission and distribution circuits to urban centres due to the interrelated nature of our network.
- Our network area is relatively compact, with rural areas relatively close to urban areas, so there is not a significant distance between rural and urban locations, minimising the difference in circuit length.
- Service quality is not differentiated by location. Network reliability standards are based on the aggregated load for all consumers supplied by the relevant section of the network. Fault response times are similar for rural and urban connections because all connections are located within a 30-minute drive from the closest depot (Levin or Paraparaumu).
- The Electricity Industry Act 2010 includes provisions for regulations that may be applied to distributors that would limit price increases in rural areas. We have chosen to limit prices (and price increases) for rural consumers by not differentiating between urban and rural consumers.

New connections in remote rural areas are potentially one area where we see off-grid solutions being economic. This is because the costs of deploying lines to remote areas for only a handful of consumers can be very expensive. We have a relatively compact and dense network, meaning this example is relatively uncommon.

Avoidable costs

The avoidable costs associated with a consumer group are the costs that would be avoided should the distribution business no longer serve that consumer group (while supplying all other remaining groups). If a consumer group were to be charged its avoided cost, it would be economically beneficial for the business to stop supplying that consumer group as revenue would not cover the avoided costs. Consistent with the Practice Note, avoided costs include short-term future cash costs, such as repairs and maintenance, billing and consumer service costs, and transmission charges.

ii. Reflect the impacts of network use on economic costs

Our interpretation

We have interpreted this principle to mean pricing structures are economically efficient, where they assist in signalling the economic costs of servicing different consumers' profiles. A consumer group's use of network capacity, circuit length, and connection assets are the key drivers of economic costs.

Our Pricing Methodology is primarily designed to signal future costs associated with capacity investments and specific asset costs.

Time of use (TOU)

On 1 April 2022, we adopted TOU pricing for our Low and Standard User consumer groups better to signal the economic costs of future capacity investments. Legacy pricing approaches based on kWh consumption are inefficient in that they provide an incentive for consumers to reduce consumption overall and are relatively poor at signalling economic costs. Disaggregating peak, shoulder, and off-peak consumption will help us better reflect the economic costs associated with future capacity investments, as discussed in Section F0.

Connection capacity

Differences in connection capacity costs are reflected in the low, standard, and industrial pricing categories. Low and standard consumers are generally connected to LV networks whereas industrial is connected to high voltage assets.

Streetlights

Separate streetlight charges seek to recover the cost of streetlight assets and maintenance directly.

Load control

We control water heaters connected to our network. Hot water control reduces congestion on the network and the transmission grid at peak use and helps reduce consumer prices. We discount our prices to reflect the benefit that load control provides the network.

Generation

The costs of providing export services are recognised through a generation export charge, while higher fixed charges and TOU pricing better reflect the cost of providing capacity in the network for these consumers.

Night only and boost

A night-only and night boost pricing option applies discounted prices to permanently wired and separately metered equipment predominantly used at night. Night store heaters are a common example. This equipment can be controlled to only run during off-peak night periods, encouraging consumers to use network capacity during off-peak periods when the cost of network use is low. Similarly, night boost allows energy to be used between 1 pm and 4 pm during the shoulder period when the network is less congested.

Dedicated assets

Large Industrial consumers are charged for dedicated assets directly.

Power factor premium

Where the power factor is less than 0.95, we reserve the right to impose a power factor premium on commercial consumers. The premium recognises lower power factors can influence circuit capacity. The premium is based on a multiplier of 2% of the monthly total network price for every 0.01 power factor below 0.95 lagging.

iii. Reflect the differences in network services provided to (or by) consumers

Our interpretation

We have interpreted this principle to mean we should offer service-based pricing to allow consumers to choose between different service levels based on the different service costs.

Self-assessment

The key service we provide is access to the network. Distinctions are made in pricing for the type of end consumer, TOU, capacity size, and asset specification.

Specific examples of different network offerings in our Pricing Methodology are analogous to those highlighted in our response to the previous principle and include the following:

- connection capacity sizes are reflected in our Low, Standard, and Industrial User consumer groups and through capital contributions
- TOU services are provided through our TOU, Night, and Night Boost pricing structures
- flexible load (e.g. electric vehicles) and distributed energy resources (DER) have a separate pricing option targeted to their needs through TOU, Flexi and Export pricing
- streetlights are charged specifically for their assets
- unmetered loads have separate prices reflecting the varying circumstances of these connections and the lack of metering information
- non-standard asset specifications and load sizes are catered for through industrial and non-standard pricing.

vi. Encourage efficient network alternatives

Our interpretation

We have interpreted this principle to mean network prices should also generally fall below the standalone cost of network alternatives to discourage inefficient bypassing of the network. As discussed in Principle A subprinciple i above, average charges are estimated to be less than standalone costs for all consumer groups. Therefore, they discourage consumers from investing in inefficient off-grid energy solutions.

Self-assessment

Small-scale distributed generation such as roof-top Solar Photovoltaic (Solar PV) is the main network alternative to grid-connected electricity. The number of distributed generators connected to the network is currently relatively limited and is almost entirely Solar PV without batteries. Natural gas and LPG energy sources are also a partial substitute for electricity.

Network pricing should also signal the cost of efficient investments in alternatives to the network to give consumers information on investment decisions.

Although investments in Solar PV are encouraged on our network, this generation load is not typically available to reduce demand at the network peak when our cost to serve is highest, for example, on a winter evening. Anytime consumption charges encourage inefficient investments in Solar PV as consumer charges decrease with the onsite generation, but costs to serve do not.

TOU pricing structures (recently introduced) are more effective at signalling efficient investments in network alternatives such as PV. Consumers cannot fully avoid the cost of using the network at peak times when solar generation is typically lower.

Our plan to increase fixed charges for domestic consumers in line with the phaseout of the LFC Regulations will also ensure every consumer pays a minimum contribution to network costs, despite their level of consumption. This also recognises consumers with solar still contribute to the cost of serving peak demand.

Principle B: Where price that signal economic costs would under-recover target revenues, the shortfall should be made up by prices that least distort network use

Our interpretation

We have interpreted this principle to mean Residual costs are the remaining costs we recover from prices after deducting revenue recovered from prices that signal economic costs under Principle A. Economic cost pricing under Principle A may under-recover total target revenue, especially where economic costs are low, which is currently the case for our prices. Residual cost should be recovered through non-distortionary pricing mechanisms following Principle B.

Self-assessment

Non-distortionary pricing mechanisms included fixed prices, either charged on a daily or connection size basis. All consumers contribute to residual network costs mainly through the fixed component of prices. These cause minimal distortion because these prices do not change with consumer usage behaviour, and consumers cannot avoid these charges.

Until recently, the low fixed charge regulations have limited how much revenue can be recovered from domestic consumers, who comprise most of our consumer base. Our pricing strategy involves increasing the proportion of revenue from fixed charges consistent with the five-year phase-out of the low fixed charge regulations. Over time we will seek to align our fixed pricing structures to our residual costs.

Principle C: Prices should be responsive to the requirements and circumstances of end users by allowing negotiation to

i. Reflect the economic value of services

Our interpretation

We have interpreted this principle to mean our prices should meet consumers' needs and expectations. And where standard prices do not, we should offer consumers a non-standard contract that better meets their needs and expectations.

Self-assessment

Our prices reflect the different network service offerings responsive to consumers' needs. Consumers can move price categories to meet their required level of service. Non-standard terms are not currently required, but we are open to discussing nonstandard terms that better reflect the economic value of the service.

Avoided and standalone costs form the boundaries within which prices are negotiated and set to ensure services reflect fair economic value.

Prices above standalone costs are unlikely to be sustainable in a market for alternative energy sources and may result in the inefficient bypass of the existing infrastructure. We set our prices below standalone costs and above-avoided costs for each consumer group. We would seek to do this for non-standard connections, therefore recovering the economic cost of supply for each consumer group.

ii. Enable price/quality trade-offs

Consumers can make price and quality trade-offs in the following ways through our pricing:

- TOU, Night, and Night Boost pricing allows consumers to select pricing options that allow them to make trade-offs on when they use electricity
- Controlled pricing plans have lower prices to recognise the network can turn off the consumer's hot water load to manage the network load
- we are open to non-standard arrangements that may allow for different service levels and security of supply standards (i.e. N-2 redundancy).

Principle D: Development of prices should be transparent and have regard to transaction costs, consumer impacts, and uptake incentives

Our interpretation

We interpret this principle as following good pricing practices when developing our prices. As our prices evolve over the next five years to become more cost-reflective, we must ensure stakeholders are brought along on our journey. We must be mindful not to confuse, add unnecessary costs, ignore consumer impacts, or fail to be incentivised to make necessary changes.

Self-assessment

Our pricing is simple and limited to most consumers fixed daily and variable consumption prices.

Our Pricing Methodology and annual price changes are published on our website at: https://electra.co.nz.

Our disclosures provide relevant information that consumers and retailers need to understand how prices are set. We have sought to reduce retailer transaction costs by developing pricing to reflect industry standard terminology, consumer profiles, and connection characteristics, where possible.

Appendix C – Explanation of our price options

Name	Description	Code	Consumption Time period		Unit of measure
Residential / Small to Medium enterprises (SMEs)		Low, Standard			
Fixed Price	Daily fixed charge applicable to non-TOU customers.	F, AF			day
Uncontrolled	A standard price for using electricity at any time of the day.	A, AA	Anytime		kWh
Controlled 20	Customers may pay a lower price for hot water heating (and other uses) by allowing supply to be interrupted. We can switch the load off for up to 4 hours per day under this price.	M, TEVM, MAA, XTM, XTEVM	Anytime, control is limited to 4 hours a day		kWh
Night	The Night rate reflects the spare capacity on the network during the period. The Night rate does not function as a standalone option and must be on a circuit during these hours, used in conjunction with another price option for another load.	N, NOA	Night only	2300-0700	kWh
Night Boost	As for Night, with the addition of an afternoon heating boost.	B, BA	Night	2300-0700	kWh
			Day	1300-1600	kWh
Day/Night	For continuous electricity supply at two times of use prices: a night-time rate set for the 10 hours between 21:00 and 7:00; and a peak rate during the day.	DN, DNA	Night	2100-0700	kWh
		DD, DDA	Day	0700-2100	kWh
Export	For those that are generating electricity and exporting some or all of this.	EX	Anytime		kWh
Fixed Price TOU	Daily fixed charge applicable to TOU customers.	TF, XTF			day
Time of Use (TOU)	A three-rate (peak, off-peak, and night) TOU option is available to all customers with the ability to move a load or otherwise take advantage of price signals. There is an additional option for a separately metered controlled load.	TN, XTN	Off-Peak	2300-0700	kWh
		TP, XTP	Peak	0700-1100	kWh
				1700-2100	kWh
		TO, XTO	Sholder	1100-1700	kWh
				2100-2300	kWh
Fixed Price – Flexi Pricing	Daily fixed charge applicable to TOU customers that participate in our pricing tiral.	TEVF, XTEVF			day
Time of Use Flexi Pricing	Time-of-use consumption charges applicable to TOU customers that participate in our pricing tiral.	TEVN, XTEVN	Off-Peak	2300-0700	
		TEVP, XTEVP	Peak	0700-1100	kWh
				1700-2100	
		TEVO, XTEVO	Sholder	1100-1700	kWh
				2100-2300	kWh

Name	Description	Code	Consumption Time period		Unit of measure
Large customers		Industrial			
Fixed Price - Industrial	A daily fixed charge applies to customers on the Industrial pricing option.	S	Anytime		day
TOU - Industrial	A three-rate (peak, off-peak, and night) TOU option differs from the TOU price by higher fixed and lower variable charges. It targets larger commercial customers by rewarding those able to move the load away from the peak or take advantage of price signals.	SN	Off-Peak	2300-0700	
		SP	Peak	0700-1100	kWh
				1700-2100	kWh
		SO	Sholder	1100-1700	kWh
				2100-2300	kWh
Industrial Capacity	Related to the size of an ICPs connection and related equipment needed for its energy demand. A chargeable capacity multiplier is maintained in the registry. The chargeable capacity from the registry is multiplied by the price from the price schedule to determine the daily cost.	SCAP	Anytime		kVA/day
Power Factor	Where the power factor is less than 0.95, we reserve the right to impose a power factor premium. The premium will be based on a multiplier of 2% of the monthly total network price for every 0.01 power factor below 0.95 lagging.	PWRF	Anytime		dollar/0.01 lagging
Unmetered		Unmetered			
Unmetered Energy	Unmetered Energy Charge.	U	Timetable		kWh
Unmetered Maintenance	Recovers costs of maintaining unmetered Items.	CM	Each Item		Item/day
Lighting	All current under veranda lighting.	LGT	Each Fitting		fitting/day

Appendix D – Delivery charges effective 1 April 2024

Delivery charges (i.e., includes Distribution, Pass-through, and Transmission prices as a single price) are shown in Table 43.

Table 43: Delivery charges effective 1 April 2024

Consumer Group		Price Category		Quantity	Unit	1 April 2023	1 April 2024	Price 2024 Post Discount	Change in Prices	
Low Users (<= 8,000 kWh per year)	General Pricing	Fixed daily	F	23,672	$/con/day	$0.4500	$0.6000	$0.4630	+$0.1500	+33%
		Uncontrolled/Anytime	A	126,123,083	$/kWh	$0.1400	$0.1333	$0.1274	($0.0067)	-5%
		Night of Day/Night (9pm-7am)	DN	2,632,657	$/kWh	$0.0770	$0.0636	$0.0577	($0.0134)	-17%
		Day of Day/Night (7am-9pm)	DD	3,714,063	$/kWh	$0.1660	$0.1478	$0.1419	($0.0182)	-11%
		Controlled 20 (electric hot water)	M	33,699,712	$/kWh	$0.0840	$0.0842	$0.0783	+$0.0002	+0.3%
		Night only (11pm-7am)	N	2,660,302	$/kWh	$0.0740	$0.0742	$0.0681	+$0.0002	+0.3%
		Night Boost (11pm-7am & 1pm-4pm)	B	2,297,352	$/kWh	$0.0780	$0.0782	$0.0723	+$0.0002	+0.3%
	TOU Pricing	Fixed daily	TF	14,671	$/con/day	$0.4500	$0.6000	$0.4630	+$0.1500	+33%
		Off-Peak (11pm-7am)	TN	20,045,249	$/kWh	$0.0740	$0.0603	$0.0544	($0.0137)	-19%
		Peak (7am-11am & 5pm-9pm)	TP	35,028,592	$/kWh	$0.1460	$0.1580	$0.1521	+$0.0120	+8%
		Shoulder (11am-5pm & 9pm-11pm)	TO	22,560,720	$/kWh	$0.1110	$0.1110	$0.1051	($0.0000)	-
		Controlled 20 (electric hot water)	M	33,700,210	$/kWh	$0.0840	$0.0842	$0.0783	+$0.0002	+0.2%
		Night Boost (11pm-7am & 1pm-4pm)	B	2,297,388	$/kWh	$0.0780	$0.0782	$0.0723	+$0.0002	+0.3%
	Flexi Pricing	Fixed daily	TEVF	11	$/con/day	$0.4500	$0.6000	$0.4630	+$0.1500	+33%
		Off-Peak (11pm-7am)	TEVN	26,524	$/kWh	$0.0670	$0.0583	$0.0524	($0.0087)	-13%
		Peak (7am-11am & 5pm-9pm)	TEVP	18,534	$/kWh	$0.1460	$0.1451	$0.1392	($0.0009)	-1%
		Shoulder (11am-5pm & 9pm-11pm)	TEVO	9,886	$/kWh	$0.1110	$0.1195	$0.1136	+$0.0085	+8%
		Controlled 20 (electric hot water)	TEVM	2,288	$/kWh	$0.0840	$0.0842	$0.0783	+$0.0002	+0.2%

Consumer Group		Price Category		Quantities	Unit	1 April 2023	1 April 2024	Price 2024 Post Discount	Change in Prices	
Standard Users (>8,000 kWh per year)	General Pricing	Fixed daily	AF	2,435	$/con/day	$1.3100	$1.7423	$1.6053	+$0.4323	+33%
		Uncontrolled/Anytime	AA	19,700,893	$/kWh	$0.1010	$0.0812	$0.0022	($0.0198)	-20%
		Night of Day/Night (9pm-7am)	DNA	139,931	$/kWh	$0.0380	$0.0114	$0.1000	($0.0266)	-70%
		Day of Day/Night (7am-9pm)	DDA	272,448	$/kWh	$0.1270	$0.0957	$0.0530	($0.0313)	-25%
		Controlled 20 (electric hot water)	MAA	2,332,038	$/kWh	$0.0450	$0.0321	$0.0262	($0.0129)	-29%
		Night only (11pm-7am)	NOA	20,493	$/kWh	$0.0350	$0.0221	$0.0160	($0.0129)	-37%
		Night Boost (11pm-7am & 1pm-4pm)	BA	94,050	$/kWh	$0.0390	$0.0261	$0.0202	+$0.0129	-33%
	TOU Pricing	Fixed daily	XTF	5,424	$/con/day	$1.3100	$1.7423	$1.6053	+$0.4323	+33%
		Off-Peak (11pm-7am)	XTN	13,137,262	$/kWh	$0.0350	$0.0081	$0.0022	($0.0269)	-77%
		Peak (7am-11am & 5pm-9pm)	XTP	25,325,446	$/kWh	$0.1070	$0.1058	$0.1000	($0.0012)	-1%
		Shoulder (11am-5pm & 9pm-11pm)	XTO	17,980,206	$/kWh	$0.0720	$0.0588	$0.0530	($0.0132)	-18%
		Controlled 20 (electric hot water)	XTM	6,803,316	$/kWh	$0.0450	$0.0321	$0.0262	($0.0129)	-29%
		Night Boost (11pm-7am & 1pm-4pm)	XTB	42,481	$/kWh	$0.0390	$0.0261	$0.0202	($0.0129)	-33%
	Flexi Pricing	Fixed daily	XTEVF	5	$/con/day	$1.3100	$1.7423	$1.6053	+$0.4323	+33%
		Off-Peak (11pm-7am)	XTEVN	13,459	$/kWh	$0.0280	$0.0061	$0.0002	($0.0219)	-78%
		Peak (7am-11am & 5pm-9pm)	XTEVP	12,692	$/kWh	$0.1070	$0.0929	$0.0870	($0.0141)	-13%
		Shoulder (11am-5pm & 9pm-11pm)	XTEVO	8,275	$/kWh	$0.0720	$0.0674	$0.0615	($0.0046)	-6%
		Controlled 20 (electric hot water)	XTEVM	3,018	$/kWh	$0.0450	$0.0321	$0.0262	($0.0129)	-29%
Industrial (>40,000 kWh per year)		Fixed daily	S	285	$/con/day	$3.1000	$4.1230	$3.9860	+$1.0230	+33%
		Off-Peak (11pm-7am)	SN	28,162,334	$/kWh	$0.0230	$0.0081	$0.0022	($0.0149)	-65%
		Peak (7am-11am & 5pm-9pm)	SP	41,035,580	$/kWh	$0.0810	$0.0842	$0.0783	+$0.0032	+4%
		Shoulder (11am-5pm & 9pm-11pm)	SO	40,613,149	$/kWh	$0.0560	$0.0459	$0.0400	($0.0101)	-18%
		Capacity	SCAP	-	$/kVA/day	-	-	-	-	-
Unmetered		Unmetered/Streetlighting	U	1,089,513	$/kWh	$0.1500	$0.1500	$0.1500	-	-
		Lighting	LGT	8,882	$/fitting/day	$0.2400	$0.2406	$0.2406	+$0.0006	+0.3%
		Lighting Consumption	LGTU	-	$/kWh	-	-	-	-	-
Export		Small scale distributed generation	EX	-	$/kWh	-	-	-	-	-

Appendix E – Breakdown of the Required Revenue by GXP and Consumer Group

Table 44 shows the allocation of our Revenue Requirement by cost component and cost drive to the Mangahao and Paraparaumu GXPs.

Table 44: Required Revenue allocated to GXP by cost component and cost driver for the pricing year

Cost Component	Cost Category	Cost Driver	Price Recovery Category	Required Revenue		
				Mangahao	Paraparaumu	Total
Service Interruptions and Emergencies	Operating Expenditure	Consumption	Distribution	$991,508	$1,415,187	$2,406,695
Vegetation Management	Operating Expenditure	Line Length	Distribution	$573,232	$1,436,098	$2,009,330
Routine and Corrective Maintenance	Operating Expenditure	Asset Utilisation	Distribution	$918,083	$1,430,841	$2,348,924
Asset Replacement and Renewal	Operating Expenditure	Installed capacity	Distribution	$236,110	$367,980	$604,090
System Operations and Network Support	Operating Expenditure	Installed capacity	Distribution	$2,845,069	$4,434,065	$7,279,134
Business Support	Operating Expenditure	Installed capacity	Distribution	$3,082,995	$4,804,875	$7,887,870
Council Rates	Rates & Levies	Attributable Cost	Pass-through	$81,370	$103,000	$184,370
Commerce Act Levies	Rates & Levies	Consumption	Pass-through	$13,154	$18,776	$31,930
Electricity Authority Levies	Rates & Levies	Attributable Cost	Pass-through	$35,484	$52,179	$87,663
Utilities Disputes Levies	Rates & Levies	Consumption	Pass-through	$11,881	$16,959	$28,840
FENZ Levies	Rates & Levies	No. of ICPs	Pass-through	$18,220	$29,160	$47,380
Settlement Residue Allocation Methodology (SRAM)	Transmission	No. of ICPs	Transmission	-	-	-
Connection Charge	Transmission	No. of ICPs	Transmission	$653,921	$1,046,577	$1,700,498
Benefit-based charges (BBC)	Transmission	No. of ICPs	Transmission	$501,444	$802,543	$1,303,987
Residual Charge	Transmission	Asset Utilisation	Transmission	$2,394,166	$3,731,330	$6,125,496
Transitional Cap	Transmission	Attributable Cost	Transmission	$2,444	$3,488	$5,932
New investment charges	Transmission	Attributable Cost	Transmission	$96,490	$578,515	$675,004
Avoided cost of transmission (ACOT)	Transmission	Attributable Cost	Transmission	-	-	-
Shared Benefit Mangahao embedded generation (ACOD)	Operating Expenditure	Attributable Cost	Distribution	$280,000	-	$280,000
Depreciation - Network Assets	Depreciation	Attributable Cost	Distribution	$6,793,722	$9,696,730	$16,490,452
Depreciation - Non-network Assets	Depreciation	Attributable Cost	Distribution	$663,708	$947,315	$1,611,023
Capital Contributions	Other Regulated Income	Attributable Cost	Distribution	-	-	-
Return on Investment	Return on Investment	Attributable Cost	Distribution	$2,573,620	$3,676,778	$6,250,397
Regulatory Tax Allowance	Regulatory Tax Allowance	Attributable Cost	Distribution	$720,613	$1,029,498	$1,750,111
		Total Cost to Serve by Location		**$23,487,235**	**$35,621,893**	**$59,109,128**

The allocation of our Revenue Requirement by GXP, by cost component, based on the Low Users Consumer Group's cost drivers is shown in Table 45.

Table 45: Required Revenue allocated to the Low User Consumer Group for the pricing year

Cost Component	Cost Category	Cost Driver	Price Recovery Category	Required Revenue		
				Mangahao	Paraparaumu	Total
Service Interruptions and Emergencies	Operating Expenditure	Asset Utilisation	Distribution	$783,326	$1,100,808	$1,884,133
Vegetation Management	Operating Expenditure	Asset Utilisation	Distribution	$452,873	$1,117,073	$1,569,946
Routine and Corrective Maintenance	Operating Expenditure	Asset Utilisation	Distribution	$725,318	$1,112,984	$1,838,302
Asset Replacement and Renewal	Operating Expenditure	Asset Utilisation	Distribution	$186,535	$286,234	$472,769
System Operations and Network Support	Operating Expenditure	Consumption	Distribution	$1,533,552	$2,642,865	$4,176,417
Business Support	Operating Expenditure	Consumption	Distribution	$1,661,799	$2,863,882	$4,525,681
Council Rates	Rates & Levies	No. of ICPs	Pass-through	$65,048	$78,944	$143,992
Commerce Act Levies	Rates & Levies	No. of ICPs	Pass-through	$10,516	$14,390	$24,906
Electricity Authority Levies	Rates & Levies	No. of ICPs	Pass-through	$28,366	$39,992	$68,359
Utilities Disputes Levies	Rates & Levies	No. of ICPs	Pass-through	$9,498	$12,998	$22,496
FENZ Levies	Rates & Levies	No. of ICPs	Pass-through	$14,565	$22,350	$36,915
Settlement Residue Allocation Methodology (SRAM)	Transmission	Consumption	Transmission	-	-	-
Connection Charge	Transmission	Installed capacity	Transmission	$516,621	$814,083	$1,330,704
Benefit-based charges (BBC)	Transmission	Installed capacity	Transmission	$396,158	$624,261	$1,020,419
Residual Charge	Transmission	Installed capacity	Transmission	$1,891,475	$2,902,426	$4,793,901
Transitional Cap	Transmission	Installed capacity	Transmission	$1,931	$2,713	$4,644
New investment charges	Transmission	Installed capacity	Transmission	$76,230	$449,999	$526,229
Avoided cost of transmission (ACOT)	Transmission	Installed capacity	Transmission	-	-	-
Shared Benefit Mangahao embedded generation (ACOD)	Operating Expenditure	Installed capacity	Distribution	$221,210	-	$221,210
Depreciation - Network Assets	Depreciation	Installed capacity	Distribution	$5,367,276	$7,542,631	$12,909,908
Depreciation - Non-network Assets	Depreciation	Installed capacity	Distribution	$524,352	$736,872	$1,261,224
Capital Contributions	Other Regulated Income	Consumption	Distribution	-	-	-
Return on Investment	Return on Investment	Consumption	Distribution	$1,387,235	$2,191,494	$3,578,729
Regulatory Tax Allowance	Regulatory Tax Allowance	Consumption	Distribution	$388,426	$613,618	$1,002,044
		Total Cost to Serve by Location		**$16,242,309**	**$25,170,619**	**$41,412,929**

The allocation of our Revenue Requirement by GXP, by cost component, based on the Standard Users Consumer Group's cost drivers is shown in Table 46.

Table 46: Required Revenue allocated to the Standard User Consumer Group for the pricing year

Cost Component	Cost Category	Cost Driver	Price Recovery Category	Required Revenue		
				Mangahao	Paraparaumu	Total
Service Interruptions and Emergencies	Operating Expenditure	Asset Utilisation	Distribution	$137,863	$244,561	$382,424
Vegetation Management	Operating Expenditure	Asset Utilisation	Distribution	$79,704	$248,175	$327,879
Routine and Corrective Maintenance	Operating Expenditure	Asset Utilisation	Distribution	$127,654	$247,266	$374,920
Asset Replacement and Renewal	Operating Expenditure	Asset Utilisation	Distribution	$32,830	$63,591	$96,421
System Operations and Network Support	Operating Expenditure	Consumption	Distribution	$514,926	$1,067,374	$1,582,301
Business Support	Operating Expenditure	Consumption	Distribution	$557,988	$1,156,636	$1,714,625
Council Rates	Rates & Levies	No. of ICPs	Pass-through	$14,883	$22,800	$37,683
Commerce Act Levies	Rates & Levies	No. of ICPs	Pass-through	$2,406	$4,156	$6,562
Electricity Authority Levies	Rates & Levies	No. of ICPs	Pass-through	$6,490	$11,550	$18,040
Utilities Disputes Levies	Rates & Levies	No. of ICPs	Pass-through	$2,173	$3,754	$5,927
FENZ Levies	Rates & Levies	No. of ICPs	Pass-through	$3,332	$6,455	$9,787
Settlement Residue Allocation Methodology (SRAM)	Transmission	Consumption	Transmission	-	-	-
Connection Charge	Transmission	Installed capacity	Transmission	$90,924	$180,861	$271,785
Benefit-based charges (BBC)	Transmission	Installed capacity	Transmission	$69,723	$138,689	$208,412
Residual Charge	Transmission	Installed capacity	Transmission	$332,894	$644,819	$977,712
Transitional Cap	Transmission	Installed capacity	Transmission	$340	$603	$943
New investment charges	Transmission	Installed capacity	Transmission	$13,416	$99,974	$113,391
Avoided cost of transmission (ACOT)	Transmission	Installed capacity	Transmission	-	-	-
Shared Benefit Mangahao embedded generation (ACOD)	Operating Expenditure	Installed capacity	Distribution	$38,932	-	$38,932
Depreciation - Network Assets	Depreciation	Installed capacity	Distribution	$944,624	$1,675,712	$2,620,336
Depreciation - Non-network Assets	Depreciation	Installed capacity	Distribution	$92,284	$163,707	$255,992
Capital Contributions	Other Regulated Income	Consumption	Distribution	-	-	-
Return on Investment	Return on Investment	Consumption	Distribution	$465,797	$885,079	$1,350,876
Regulatory Tax Allowance	Regulatory Tax Allowance	Consumption	Distribution	$130,423	$247,822	$378,245
		Total Cost to Serve by Location		**$3,659,607**	**$7,113,586**	**$10,773,193**

The allocation of our Revenue Requirement by GXP, by cost component, based on the Industrial Consumer Group's cost drivers is shown in Table 47.

Table 47: Required Revenue allocated to the Industrial Consumer Group for the pricing year

Cost Component	Cost Category	Cost Driver	Price Recovery Category	Required Revenue		
				Mangahao	Paraparaumu	Total
Service Interruptions and Emergencies	Operating Expenditure	Asset Utilisation	Distribution	$41,583	$39,452	$81,036
Vegetation Management	Operating Expenditure	Asset Utilisation	Distribution	$24,041	$40,035	$64,076
Routine and Corrective Maintenance	Operating Expenditure	Asset Utilisation	Distribution	$38,504	$39,889	$78,393
Asset Replacement and Renewal	Operating Expenditure	Asset Utilisation	Distribution	$9,902	$10,259	$20,161
System Operations and Network Support	Operating Expenditure	Consumption	Distribution	$790,729	$707,223	$1,497,952
Business Support	Operating Expenditure	Consumption	Distribution	$856,855	$766,367	$1,623,222
Council Rates	Rates & Levies	No. of ICPs	Pass-through	$623	$511	$1,134
Commerce Act Levies	Rates & Levies	No. of ICPs	Pass-through	$101	$93	$194
Electricity Authority Levies	Rates & Levies	No. of ICPs	Pass-through	$272	$259	$531
Utilities Disputes Levies	Rates & Levies	No. of ICPs	Pass-through	$91	$84	$175
FENZ Levies	Rates & Levies	No. of ICPs	Pass-through	$140	$145	$284
Settlement Residue Allocation Methodology (SRAM)	Transmission	Consumption	Transmission	-	-	-
Connection Charge	Transmission	Installed capacity	Transmission	$27,425	$29,176	$56,601
Benefit-based charges (BBC)	Transmission	Installed capacity	Transmission	$21,030	$22,373	$43,404
Residual Charge	Transmission	Installed capacity	Transmission	$100,410	$104,022	$204,432
Transitional Cap	Transmission	Installed capacity	Transmission	$102	$97	$200
New investment charges	Transmission	Installed capacity	Transmission	$4,047	$16,128	$20,175
Avoided cost of transmission (ACOT)	Transmission	Installed capacity	Transmission	-	-	-
Shared Benefit Mangahao embedded generation (ACOD)	Operating Expenditure	Installed capacity	Distribution	$11,743	-	$11,743
Depreciation - Network Assets	Depreciation	Installed capacity	Distribution	$284,925	$270,325	$555,249
Depreciation - Non-network Assets	Depreciation	Installed capacity	Distribution	$27,836	$26,409	$54,245
Capital Contributions	Other Regulated Income	Consumption	Distribution	-	-	-
Return on Investment	Return on Investment	Consumption	Distribution	$715,285	$586,438	$1,301,723
Regulatory Tax Allowance	Regulatory Tax Allowance	Consumption	Distribution	$200,280	$164,203	$364,482
		Total Cost to Serve by Location		**$3,155,924**	**$2,823,487**	**$5,979,411**

The allocation of our Revenue Requirement by GXP, by cost component, based on the Unmetered Consumer Group's cost drivers is shown in Table 48.

Table 48: Required Revenue allocated to the Industrial Consumer Group for the pricing year

Cost Component	Cost Category	Cost Driver	Price Recovery Category	Required Revenue		
				Mangahao	Paraparaumu	Total
Service Interruptions and Emergencies	Operating Expenditure	Asset Utilisation	Distribution	$28,736	$30,366	$59,102
Vegetation Management	Operating Expenditure	Asset Utilisation	Distribution	$16,613	$30,814	$47,428
Routine and Corrective Maintenance	Operating Expenditure	Asset Utilisation	Distribution	$26,608	$30,702	$57,310
Asset Replacement and Renewal	Operating Expenditure	Asset Utilisation	Distribution	$6,843	$7,896	$14,739
System Operations and Network Support	Operating Expenditure	Consumption	Distribution	$5,862	$16,602	$22,464
Business Support	Operating Expenditure	Consumption	Distribution	$6,352	$17,991	$24,343
Council Rates	Rates & Levies	No. of ICPs	Pass-through	$816	$745	$1,561
Commerce Act Levies	Rates & Levies	No. of ICPs	Pass-through	$132	$136	$268
Electricity Authority Levies	Rates & Levies	No. of ICPs	Pass-through	$356	$377	$733
Utilities Disputes Levies	Rates & Levies	No. of ICPs	Pass-through	$119	$123	$242
FENZ Levies	Rates & Levies	No. of ICPs	Pass-through	$183	$211	$394
Settlement Residue Allocation Methodology (SRAM)	Transmission	Consumption	Transmission	-	-	-
Connection Charge	Transmission	Installed capacity	Transmission	$18,952	$22,456	$41,408
Benefit-based charges (BBC)	Transmission	Installed capacity	Transmission	$14,533	$17,220	$31,753
Residual Charge	Transmission	Installed capacity	Transmission	$69,388	$80,063	$149,451
Transitional Cap	Transmission	Installed capacity	Transmission	$71	$75	$146
New investment charges	Transmission	Installed capacity	Transmission	$2,796	$12,413	$15,210
Avoided cost of transmission (ACOT)	Transmission	Installed capacity	Transmission	-	-	-
Shared Benefit Mangahao embedded generation (ACOD)	Operating Expenditure	Installed capacity	Distribution	$8,115	-	$8,115
Depreciation - Network Assets	Depreciation	Installed capacity	Distribution	$196,896	$208,063	$404,959
Depreciation - Non-network Assets	Depreciation	Installed capacity	Distribution	$19,236	$20,327	$39,562
Capital Contributions	Other Regulated Income	Consumption	Distribution	-	-	-
Return on Investment	Return on Investment	Consumption	Distribution	$5,302	$13,767	$19,069
Regulatory Tax Allowance	Regulatory Tax Allowance	Consumption	Distribution	$1,485	$3,855	$5,339
		Total Cost to Serve by Location		**$429,395**	**$514,200**	**$943,595**

The allocation of our Revenue Requirement by GXP, by cost component, based on the Export Consumer Group's cost drivers is shown in Table 49.

Table 49: Required Revenue allocated to the Export Consumer Group for the pricing year

Cost Component	Cost Category	Cost Driver	Price Recovery Category	Required Revenue		
				Mangahao	Paraparaumu	Total
Service Interruptions and Emergencies	Operating Expenditure	Asset Utilisation	Distribution	-	-	-
Vegetation Management	Operating Expenditure	Asset Utilisation	Distribution	-	-	-
Routine and Corrective Maintenance	Operating Expenditure	Asset Utilisation	Distribution	-	-	-
Asset Replacement and Renewal	Operating Expenditure	Asset Utilisation	Distribution	-	-	-
System Operations and Network Support	Operating Expenditure	Consumption	Distribution	-	-	-
Business Support	Operating Expenditure	Consumption	Distribution	-	-	-
Council Rates	Rates & Levies	No. of ICPs	Pass-through	-	-	-
Commerce Act Levies	Rates & Levies	No. of ICPs	Pass-through	-	-	-
Electricity Authority Levies	Rates & Levies	No. of ICPs	Pass-through	-	-	-
Utilities Disputes Levies	Rates & Levies	No. of ICPs	Pass-through	-	-	-
FENZ Levies	Rates & Levies	No. of ICPs	Pass-through	-	-	-
Settlement Residue Allocation Methodology (SRAM)	Transmission	Consumption	Transmission	-	-	-
Connection Charge	Transmission	Installed capacity	Transmission	-	-	-
Benefit-based charges (BBC)	Transmission	Installed capacity	Transmission	-	-	-
Residual Charge	Transmission	Installed capacity	Transmission	-	-	-
Transitional Cap	Transmission	Installed capacity	Transmission	-	-	-
New investment charges	Transmission	Installed capacity	Transmission	-	-	-
Avoided cost of transmission (ACOT)	Transmission	Installed capacity	Transmission	-	-	-
Shared Benefit Mangahao embedded generation (ACOD)	Operating Expenditure	Installed capacity	Distribution	-	-	-
Depreciation - Network Assets	Depreciation	Installed capacity	Distribution	-	-	-
Depreciation - Non-network Assets	Depreciation	Installed capacity	Distribution	-	-	-
Capital Contributions	Other Regulated Income	Consumption	Distribution	-	-	-
Return on Investment	Return on Investment	Consumption	Distribution	-	-	-
Regulatory Tax Allowance	Regulatory Tax Allowance	Consumption	Distribution	-	-	-
		Total Cost to Serve by Location		**-**	-	-

Appendix F – Target Revenue from disclosed prices and forecast quantities

Target Revenue from disclosed prices and forecast quantities is shown in Table 50.

Table 50: Required Revenue from disclosed prices and forecast quantities for the pricing year

Consumer Group		Price Category		Quantities	Prices				Target Revenue			
					Distribution	Pass-thro	Trans	Delivery	Distribution	Pass-thro	Trans	Total
Low Users (<= 8,000 kWh per year)	General Pricing	Fixed daily	F	23,672	$0.0305	$0.0212	$0.5483	$0.6000	$263,416	$183,124	$4,737,628	$5,184,168
		Uncontrolled/Anytime	A	126,123,083	$0.1333	-	-	$0.1333	$16,814,204	-	-	$16,814,204
		Night of Day/Night (9pm-7am)	DN	2,632,657	$0.0636	-	-	$0.0636	$167,315	-	-	$167,315
		Day of Day/Night (7am-9pm)	DD	3,714,063	$0.1478	-	-	$0.1478	$549,072	-	-	$549,072
		Controlled 20 (electric hot water)	M	33,699,712	$0.0842	-	-	$0.0842	$2,837,871	-	-	$2,837,871
		Night only (11pm-7am)	N	2,660,302	$0.0742	-	-	$0.0742	$197,422	-	-	$197,422
		Night Boost (11pm-7am & 1pm-4pm)	B	2,297,352	$0.0782	-	-	$0.0782	$179,677	-	-	$179,677
	TOU Pricing	Fixed daily	TF	14,671	$0.0305	$0.0212	$0.5483	$0.6000	$163,423	$113,458	$2,936,068	$3,212,949
		Off-Peak (11pm-7am)	TN	20,045,249	$0.0603	-	-	$0.0603	$1,207,947	-	-	$1,207,947
		Peak (7am-11am & 5pm-9pm)	TP	35,028,592	$0.1580	-	-	$0.1580	$5,533,231	-	-	$5,533,231
		Shoulder (11am-5pm & 9pm-11pm)	TO	22,560,720	$0.1110	-	-	$0.1110	$2,503,507	-	-	$2,503,507
		Controlled 20 (electric hot water)	M	33,700,210	$0.0842	-	-	$0.0842	$2,837,871	-	-	$2,837,871
		Night Boost (11pm-7am & 1pm-4pm)	B	2,297,388	$0.0782	-	-	$0.0782	$179,677	-	-	$179,677
	Flexi Pricing	Fixed daily	TEVF	11	$0.0305	$0.0212	$0.5483	$0.6000	$122	$85	$2,201	$2,409
		Off-Peak (11pm-7am)	TEVN	26,524	$0.0583	-	-	$0.0583	$1,545	-	-	$1,545
		Peak (7am-11am & 5pm-9pm)	TEVP	18,534	$0.1451	-	-	$0.1451	$2,688	-	-	$2,688
		Shoulder (11am-5pm & 9pm-11pm)	TEVO	9,886	$0.1195	-	-	$0.1195	$1,181	-	-	$1,181
		Controlled 20 (electric hot water)	TEVM	2,288	$0.0842	-	-	$0.0842	$193	-	-	$193

Consumer Group		Price Category		Quantities	Prices				Target Revenue			
					Distribution	Pass-thro	Trans	Delivery	Distribution	Pass-thro	Trans	Total
Standard Users (>8,000 kWh per year)	General Pricing	Fixed daily	AF	2,435	$1.1674	$0.0272	$0.5478	$1.7423	$1,037,566	$24,143	$486,828	$1,548,537
		Uncontrolled/Anytime	AA	19,700,893	$0.0812	-	-	$0.0812	$1,599,658	-	-	$1,599,658
		Night of Day/Night (9pm-7am)	DNA	139,931	$0.0114	-	-	$0.0114	$1,600	-	-	$1,600
		Day of Day/Night (7am-9pm)	DDA	272,448	$0.0957	-	-	$0.0957	$26,078	-	-	$26,078
		Controlled 20 (electric hot water)	MAA	2,332,038	$0.0321	-	-	$0.0321	$74,839	-	-	$74,839
		Night only (11pm-7am)	NOA	20,493	$0.0221	-	-	$0.0221	$453	-	-	$453
		Night Boost (11pm-7am & 1pm-4pm)	BA	94,050	$0.0261	-	-	$0.0261	$2,454	-	-	$2,454
	TOU Pricing	Fixed daily	XTF	5,424	$1.1674	$0.0272	$0.5478	$1.7423	$2,311,140	$53,807	$1,084,414	$3,449,362
		Off-Peak (11pm-7am)	XTN	13,137,262	$0.0081	-	-	$0.0081	$106,976	-	-	$106,976
		Peak (7am-11am & 5pm-9pm)	XTP	25,325,446	$0.1058	-	-	$0.1058	$2,680,578	-	-	$2,680,578
		Shoulder (11am-5pm & 9pm-11pm)	XTO	17,980,206	$0.0588	-	-	$0.0588	$1,058,126	-	-	$1,058,126
		Controlled 20 (electric hot water)	XTM	6,803,316	$0.0321	-	-	$0.0321	$218,327	-	-	$218,327
		Night Boost (11pm-7am & 1pm-4pm)	XTB	42,481	$0.0261	-	-	$0.0261	$1,108	-	-	$1,108
	Flexi Pricing	Fixed daily	XTEVF	5	$1.1674	$0.0272	$0.5478	$1.7423	$2,130	$50	$1,000	$3,180
		Off-Peak (11pm-7am)	XTEVN	13,459	$0.0061	-	-	$0.0061	$83	-	-	$83
		Peak (7am-11am & 5pm-9pm)	XTEVP	12,692	$0.0929	-	-	$0.0929	$1,180	-	-	$1,180
		Shoulder (11am-5pm & 9pm-11pm)	XTEVO	8,275	$0.0674	-	-	$0.0674	$558	-	-	$558
		Controlled 20 (electric hot water)	XTEVM	3,018	$0.0321	-	-	$0.0321	$97	-	-	$97
Industrial (>40,000 kWh per year)		Fixed daily	S	285	$0.9783	$0.0234	$3.1224	$4.1230	$101,766	$2,318	$324,811	$428,895
		Off-Peak (11pm-7am)	SN	28,162,334	$0.0081	-	-	$0.0081	$229,325	-	-	$229,325
		Peak (7am-11am & 5pm-9pm)	SP	41,035,580	$0.0842	-	-	$0.0842	$3,456,837	-	-	$3,456,837
		Shoulder (11am-5pm & 9pm-11pm)	SO	40,613,149	$0.0459	-	-	$0.0459	$1,864,354	-	-	$1,864,354
		Capacity	SCAP	-	-	-	-	-	-	-	-	-
Unmetered		Unmetered/Streetlighting	U	1,089,513	$0.1500	-	-	$0.1500	$163,427	-	-	$163,427
		Lighting	LGT	8,882	$0.1663	$0.0010	$0.0734	$0.2406	$539,002	$3,198	$237,968	$780,168
		Lighting Consumption	LGTU	-	-	-	-	-	-	-	-	-
Export		Small scale distributed generation	EX	-	-	-	-	-	-	-	-	-

Appendix G – Director Certification for the Year-beginning Disclosures

(Pricing Methodology Only)

Clause 2.9.1 of section 2.9

We, Stephen Robert Armstrong and James Albert Carmichael, being directors of Electra Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

(i) The following attached information of Electra Limited prepared for the purposes of clause 2.4.1 of the Electricity Information Disclosure Determination 2012 in all material respects complies with that determination.

(ii) 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.

Stephen Robert ARMSTRONG

23 February 2024

James Albert CARMICHAEL

23 February 2024

GLOSSARY

Our pricing methodology uses standard industry terminology. To support consumers to understand our pricing decisions we have provided this glossary.

Term	Description
ACOD	Avoided Cost of Distribution recognises distribution network costs that can be minimised or eliminated through strategic operating decisions over the short or long term.
ACOT	Avoided Cost of Transmission recognises the transmission cost that can be minimised or eliminated through non-grid solutions such as embedded generation. Please note effective 1 April 2022 the Electricity Authority removed the requirement for distributors to make ACOT payment in accordance with the new transmission pricing methodology.
AMP	Asset Management Plan: A record of the company's plans to manage the network to provide a specified level of service.
Chargeable Capacity	Relates to the size of a connection and related equipment needed for its energy demand. This charge covers the cost of the assets involved in supplying electricity.
Commerce Commission	Responsible for the economic regulation of electricity distribution businesses as provided for under Part 4 of the Commerce Act 1986.
CPI	Consumer Price Index as released by New Zealand Statistics.
DDA	Default Distributor Agreement, as prescribed under Part 12A of the Code.
DER	Distributed Energy Resources, typically roof-top solar, wind-driven generators, car to the grid.
DERMS	Distributed Energy Resource Management
Electricity Authority (the Authority)	Responsible for the regulation of the New Zealand electricity market under the Electricity Participation Code 2010 (the Code).
EV	Electric Vehicles is a vehicle that uses one or mor motors for propulsion. EVs include battery electric vehicles and plug-in hybrid electric vehicles.
GWh	Gigawatt-hours refers to 1,000 megawatts of electricity supplied over a period of an hour.
GXP	Grid exit point, means any point of connection on the grid at which electricity predominately flows out of the transmission grid owned and operated by Transpower.
ICP	ICP means an installation control point is one of the following: (a) a Point of Connection at which a Customer's Installation is connected to the network; (b) a Point of Connection between the network and an embedded network; (c) a Point of Connection between the network and shared Unmetered Load.
Information Disclosure Determination	As set out in the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012, (Consolidated) – 6 July 2023.
KCDC	Kāpiti Coast District Council
kVA	Kilo Volt-Amp: Measure of apparent electrical power usage at a point in time.

Term	Description
kWh	Kilowatt-hour is a unit of energy that is commonly used to measure the amount of electricity consumed over time. One kWh is the amount of energy consumed by a 1000-watt appliance running for one hour.
Low fixed charge regulations (LFC)	As set out in the Electricity (Low Fixed Price Option for Domestic Customers) Regulations 2004. These require us to make a price option available for domestic customers at their principal place of residence. Prices must be set such that the fixed daily charge does not exceed 60 cents (excl. GST), and customers should be no worse off under this price option at 8,000 kWh relative to other prices.
MDAG	Market Development Advisory Group provide the Electricity Authority with independent advice on issues that relate to pricing and cost allocation, risk and risk management, and operational efficiencies.
MW	A megawatt is 1,000,00 watts of power, a thousand times stronger than a kilowatt.
Power Factor	The ratio of real power (e.g., kW) to apparent power (e.g., kVA). 0.95 lagging is considered operating within normal parameters on our network.
Powerswitch	Powerswitch is an EA-funded independent service that helps electricity and gas customers determine which power company and pricing plan are the cheapest.
PV	Photovoltaic – electricity-generating solar panels.
Retailer	Electricity Retailer that we supply.
SCI	Electra Statement of Corporate Intent
Sub-transmission	A power line that transports or delivers electricity at 33 kV on our network.
System Maximum Demand	Aggregate peak demand for the network, the coincident maximum sum of GXP demand, and embedded generation output.
Target revenue requirement	The revenue will be recovered through prices over the pricing year to recover our costs of investing in and operating the network.
TPM	Transmission Pricing Methodology.
TOU	Time of Use: Refers to price options that rely on meters that measure consumption at the time of use.
Transpower	Transpower New Zealand Limited: The owner and operator of the national electricity transmission network. Transpower delivers electricity from generators to distribution networks and large direct connect customers around the country.