Pricing Methodology

1 April 2026 to 31 March 2027

Electra Limited

1. Executive Summary

1.1 Purpose of the document

The primary purpose of this document is to detail Electra's approach to determining electricity line services prices for the upcoming pricing year. It provides an explanation of how we seek to set fair and reasonable prices, that reflect the actual cost of supply, while meeting regulatory requirements under the Commerce Act 1986 and the Electricity Authority's pricing principles (see p.4, *Regulatory Context*). Specifically, it outlines the transition toward more cost-reflective pricing (CRP), which aims to signal future network costs and fairly allocate residual costs among users (see p.5 *Industry Context*).

1.2 What is new for the 2026/2027 Pricing Year

Electra is implementing several significant changes to its pricing structure and methodology starting 1 April 2026:

Mandatory Time of Use (TOU) Pricing: TOU pricing is now mandatory for all connections supplied with a communicating smart meter. This is intended to accelerate the transition away from legacy uncontrolled pricing plans.

Increased Daily Fixed Charges: In line with the ongoing phase-out of the Low Fixed Charge (LFC) Regulations, Electra has increased daily fixed charges across all consumer groups to better align with the fixed-cost nature of the network.

Removal of the Shoulder Period: To simplify pricing, align with industry norms, and to reduce confusion, the 'shoulder' price period has been removed. The shoulder period hours, along with weekends, are now treated as off-peak.

Introduction of Export Rebates: A new rebate has been introduced for distributed generation (such as solar) that exports electricity back into the network during peak periods in winter.

Segmented Commercial & Industrial (C&I) Groups: The C&I consumer group has been divided into four categories—Small, Medium, Large, and Extra Large—based on annual consumption to better reflect the different costs of serving these consumers.

Transition to Capacity-Based Charging: Electra is beginning to transition large C&I consumers towards capacity-based charging (charging based on the size of the connection) rather than just consumption. Segmentation by annual consumption is the first step in this process.

Increased Revenue and Discounts: Target revenue has increased by $7.9 million (13%) to $70.6 million. Simultaneously, the total discount paid back to consumers has increased by $3.6 million, totalling $9.15 million for the year.

The discount has been included in prices, as opposed to reducing prices overall, to ensure that the full discount amount is provided to all Electra consumers. It is unreasonable to expect retailers to set Kapiti and Horowhenua specific prices that would pass the discount through, so Electra has elected to include the discount in prices and pay the discount separately to consumers.

1.3 Strategic context

This document emphasises Electra's continued commitment to Cost-Reflective Pricing, designed to incentivise consumers to shift electricity usage from congested peak periods to off-peak times. By doing so, Electra aims to defer costly network upgrades, manage emerging challenges like Electric Vehicle (EV) uptake, and support New Zealand's transition to a zero-carbon future.

Providing information on how prices are set informs consumers about how their electricity use can impact the costs of running the network. The methodology continues to balance these economic signals with the need to minimise 'bill shock' for consumers through a phased implementation approach.

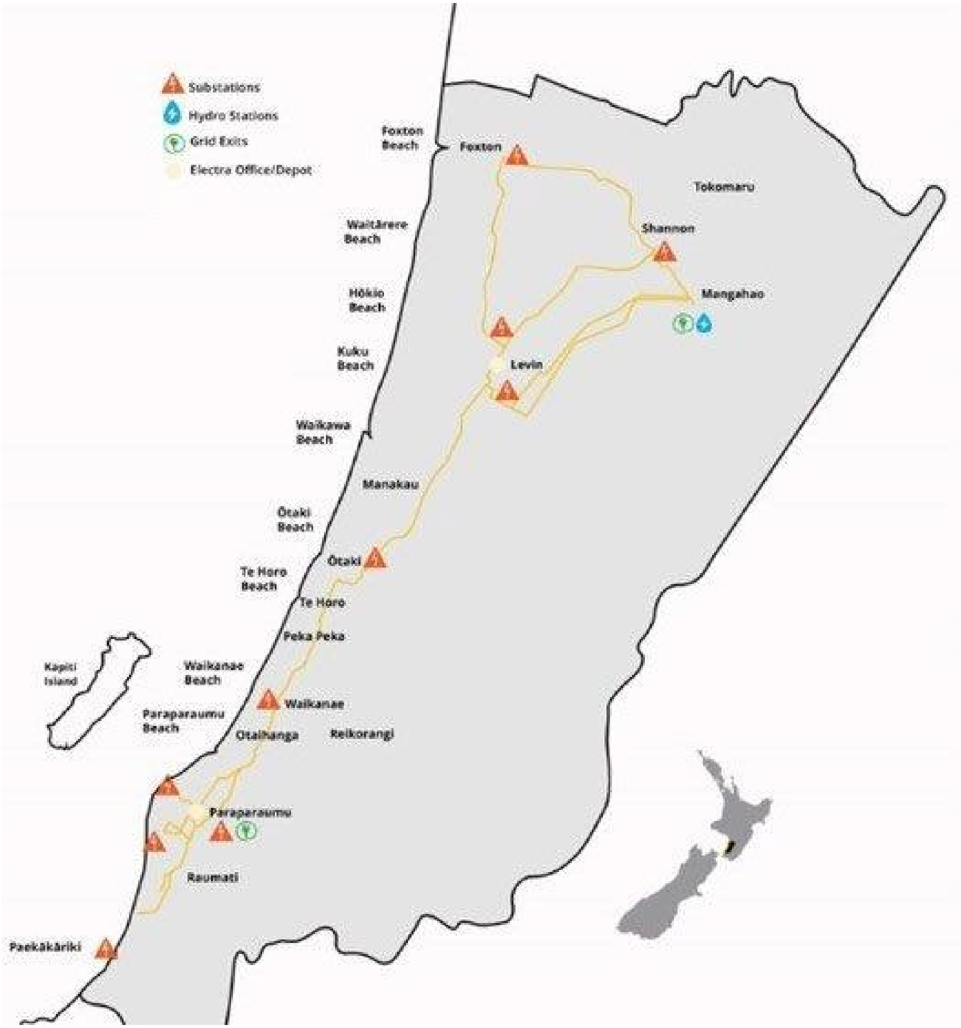
2. Introduction

Electra Limited (Electra) owns and operates the electricity distribution network covering the Kāpiti and Horowhenua regions. Stretching from Foxton and Tokomaru in the north, to the Tararua ranges in the east and Paekākāriki in the south, the network covers an area of approximately 1,628 km^2 and a population of around 95,000 residents. Electricity is distributed across a network of around 1,558 km overhead lines, 842 km underground cables, 2,686 transformers and 21,417 poles to over 47,300 connections[1]. Electra is connected to the national grid at Paraparaumu and Mangahao and supplies both urban and rural areas.

Electra is wholly owned by the Electra Trust, with shares in the company held on behalf of the over 47,300 households and businesses connected to the Electra network. The Electra Trust, whose Trustees are locally elected, represent the consumers and ensures the company acts in best interests for consumers over the long term.

As a supplier of an essential service, and consumer trust owned network, we seek to set fair and reasonable prices for consumers that have shared access to our network. This document outlines the pricing methodology (our approach) to determining prices, to reflect the cost of supply in an efficient and fair manner.

This Pricing Methodology applies to the pricing of electricity line services regulated under Part 4 of the Commerce Act 1986 and should be read in conjunction with the Pricing Schedule for 1 April 2026.



[1] ref Electra's Information Disclosure 2025 https://electra.co.nz/our-company/disclosures/

3. Regulatory Context

3.1 Commerce Act

The Commerce Commission (the Commission) regulates electricity distribution services under the Commerce Act 1986 (the Act). Under the Act, Electra is subject to Information Disclosure regulation, which is where we must complete annual disclosure of information relating to our business and performance as set out in the Electricity Distribution Information Disclosure Determination 2012.

As Electra is wholly owned by the Electra Trust, Electra meets the definition of an exempt consumer-owned Electricity Distribution Business (EDB) and is not subject to price-quality regulation. However, we still use the Commerce Commission's building block model (BBM) to inform our target revenue, and to benchmark our returns as if we were subject to price-quality regulation.

3.2 Low Fixed Charge Regulations

We must comply with the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 (the Low Fixed Charge Regulations). These regulations require us to offer residential consumers a price option at their principal place of residence, with a fixed price of no more than 90c per day (excluding GST), and where the sum of the annual fixed and volumetric charges on that price option equals any other price option available to those consumers when they use 8,000kWh per annum.

Since 2022, the Low Fixed Charge (LFC) Regulations have been progressively phased out and will no longer be in place by 1 April 2027. This change will improve our ability to offer cost-reflective pricing, as most network costs are fixed and the majority of Electra's network is residential.

3.3 Electricity Authority pricing principles

We are also guided by the Electricity Authority's (Authority) pricing principles and focus areas[2]. While compliance with the pricing principles is voluntary, the Disclosure Determination requires us to explain the rationale for any inconsistency, where we cannot demonstrate consistency.

In addition, the Electricity Industry Participation Code 2010 has specific pricing principles in Part 6 which limits us to recovering only our incremental costs from distributed generation customers. These specific principles are legally binding, and effectively limit us to recovering only the additional costs resulting from distributed generation.

4. Industry Context

Electricity networks are like roads in that they can become congested at peak times of the day. Cost-reflective pricing tries to match the cost structure of the network with the pricing structure – so fixed costs are best recovered using fixed prices and then price signals are used to demonstrate when there is capacity in our network (through lower prices), and when the network is more congested (through higher prices).

Unlike traffic on roads, electricity cannot sit in a queue and wait its turn. If, at peak times, there is more demand for electricity than the network can supply, the network will trip and there will be a power outage. As such, if we get close to the capacity of the network (and cannot reduce that demand through a price signal or other means) we must invest to upgrade the capacity in that area.

The additional cost of upgrading capacity is recovered in two ways:

[2] 2024 Open Letter to Distributors, 2022 Practice Note Second Edition v2.2, 2019 Practice Note, and the October 2022 guidance on transmission charge pass through

- Customer contributions are used for recovering the cost of new assets or increasing capacity of existing assets, where that is appropriate.
- Line charges are used to recover the cost of existing connections increasing their usage of the network.

Like roads, electricity networks rely on consumers to use the network at different times as this creates a diverse demand profile. Increased consumer usage of an electricity network can drive the need for increased network capacity and therefore corresponding cost and price increases.

Technology changes, such as more rooftop solar, batteries, and electric vehicles, will increasingly have an impact on the way that networks perform. For example, electric vehicles will increase the loads on networks, potentially meaning we need to incur cost to build more capacity to meet the demand increase. Rooftop solar injected at low voltage can assist with capacity management, but may also create voltage swings as generation ramps up and down, requiring costly upgrades.

These changes in network use are making well-designed network pricing increasingly important. This is driving reform across New Zealand (and in countries such as Australia and the UK) toward cost-reflective pricing.

4.1 What is cost-reflective pricing (CRP)?

Cost reflective prices seek to:

1. Signal future network costs, and
2. Fairly allocate residual costs

The cost of adding capacity to the network to serve growing demand should be apparent to users, through incentives to increase consumption outside of the peak periods. To reduce the need to invest in capacity upgrades, lower charges are made available to consumption that can occurs off-peak or can be controlled.

Existing capacity should be readily available for use and not deter connection. Unavoidable costs to efficiently maintain and operate the network, while adhering to reliability and safety standards, are largely fixed and should be recovered in a fair way from network users. Residual costs are recovered through fixed charges similar to the way rates are paid to councils to maintain and operate local roads.

Electra is committed to implementing good practice pricing arrangements, that play a constructive role in encouraging efficient network use and investment, for the long-term benefit of our consumers. By efficient use, we mean increasing the use of the network within its existing capacity. We can do this by incentivising users to shift load from congested periods on the network, to off-peak periods that have spare capacity. More energy delivered across the network without incurring costly upgrades means a lower cost per unit of energy delivered for all of us.

Improving the cost reflective nature of our pricing will take time to implement. We began our transition five years ago, and while we have updated the pricing structure of almost every price plan, rebalancing prices will take time as we balance the transition with impacts on customers.

The pricing structures that we have initially adopted to improve cost reflectivity may change and evolve over time, particularly as technology evolves and the market for dynamic price signals develops. For now, our focus is on Time of Use (TOU) pricing for residential, commercial and industrial consumers, with a view to introducing capacity-based or asset-based pricing for large commercial and industrial consumers in the next pricing year.

5. Our Network

5.1 Current pricing

Like most distributors in New Zealand, there is room to improve how our existing pricing arrangements signal future costs. For example, for residential 67% of revenue is expected to be recovered through variable (kWh) based prices (down from 69% in the prior year), which has improved but still does not align with our costs which are largely fixed. Re-balancing of fixed and variable prices is the key pricing reform that we are continuing to implement over the coming years – this will be aided by the removal of LFC requirements in the next pricing year.

The phasing out of the LFC requirements allows us to increase fixed charges for Low Users. As we increase fixed charges to align with standard fixed rates, we can reduce the share of revenue which needs to be recovered from variable rates. High variable rates can discourage use during times where there is capacity to consume more electricity across the network without driving network costs.

High variable charges, and in particular high peak and uncontrolled variable charges, incentivise consumers to inefficiently invest in alternate forms of technology to avoid lines charges. Some examples include wood burners, gas instant hot water heaters, or overinvesting in batteries and solar panels.

Not all these investments will be inefficient at a whole of network level. Inefficient investments, from a distribution perspective, are investments where the consumer is saving more money from their investment in alternate technologies, than the network is saving from them shifting their usage away from the network. When an investment is inefficient, the network is left with the same or similar costs after a consumer leaves, but fewer people to share those costs. This increases lines charges for the consumers who are left, who may not be able to afford investments such as batteries and solar panels to avoid lines charges. And as a whole community – the consumers who invested in alternate technologies, plus the consumers who remain paying for the network – we all end up spending more to deliver the energy we need than we otherwise would have.

Batteries and solar panels have a role to play in increasing New Zealand's renewable generation, which in turn can help lower energy prices and help meet the country's zero carbon aspirations. However, in weighing whether to invest in these technologies, consumers should have the right price signals and information to assess whether the value of the energy generated from the solar panels exceeds the cost.

Another example of the issues that current pricing can create is the impact on Electric Vehicle (EV) owners. Currently EV owners can pay up to 5-6c per kWh in lines charges for charging at home during off-peak hours (plus energy costs), even though off-peak or interruptible charging could be accommodated on our network at no incremental cost. These prices might deter consumers from investing in electric vehicles, which would be counterproductive to achieving New Zealand's zero carbon ambitions.

Pricing changes take years to develop and implement, with multi-year transitions often needed to limit bill shock. Signals then take time to flow to consumers' investment decisions and behaviours. As such, the focus for pricing reform should be on investment pressures 5-7+ years from today. Over that timeframe, price signal misalignment could drive outcomes such as:

- **Inefficient EV charging**. EV uptake is likely to grow rapidly and could cause significant network investment pressure if charging adds to peak demand. At the same time, usage charges for off-peak or interruptible demand may deter usage that would not drive any new network costs.
- **Electricity rationing**. Usage-based charges at times when there is ample network capacity deters consumption, contributing to under-heated or under-cooled homes, and suppressed electrification.
- **Unnecessary network investment**. Over time, well targeted pricing should produce flatter network demand profiles, supporting deferral of

reinforcement work and potentially avoid altogether a wave of low voltage (LV) reinforcement that may otherwise be needed to accommodate EVs or high solar uptake.

There is also a policy and regulatory focus on network pricing that reinforces the case for Cost Reflective Pricing (CRP) and adds some elements:

• **Low Fixed Charges**. The Government is phasing out the Low Fixed Charge Regulations. This will enable the increase of fixed daily charges to residential consumers, offset by reducing variable costs, reflecting the fixed cost nature of the service we provide. This enables consumers to access the unutilised capacity in our network at off-peak times, at lower cost.

• **Pricing reform.** The Authority is driving a focus on pricing reform to improve the cost reflectivity of network pricing, thereby encouraging more efficient outcomes. These factors shape the impetus for reform, and the direction of our reform strategy set out in Section 5.

5.2 Current constraints

For the majority of our network, we have no capacity constraints which we need to signal, but we do have some localised capacity constraints that we need to better signal to consumers. We have provided substation level information relating to current capacity utilisation, constraints, and planned works to alleviate these constraints in our Asset Management Plan (AMP).

Our key emerging challenges are summarised below:

Mangahao GXP

Over the last few years we have received a significant volume of new connection requests in the area supplied by this GXP. As such, to provide a quality of service commensurate with that expected by consumers, we need to both increase our capacity into the area to supply new connections, and increase the security of supply to ensure we can maintain N-1 security at all times. To address these requirements, we are currently heavily managing hot water load in the area and working with Transpower on a possible GXP upgrade. We will continue to explore non-network alternatives that can meet the security of supply and capacity requirements at a lower cost.

Data on EV uptake and small-scale distributed generation

We currently have around 2,300 registered EVs and 1,900 connections with generation capacity active within our network. So far, we are not seeing any resulting capacity or power quality issues but without access to information from smart meters we cannot accurately monitor constraints on the low voltage network. We rely on high level network studies or consumers to notify us if they believe there may be an issue. We are working through obtaining access to electricity meter information to improve our network visibility.

5.3 Supporting infrastructure

The electricity which you consume in your home or business is measured by your electricity meter, which is provided by a metering equipment provider (MEP). The readings are provided to your retailer, which uses them to bill you, and also to provide us with data so that we can bill the retailer for our lines services. The MEP who provides your metering is selected by your retailer.

To implement cost-reflective pricing, we need consumption data to set prices, and to bill for our services, under those new pricing structures. We are therefore reliant on metering providers to measure the right data, and retailers to then provide us access to that data.

Smart meters

Cost-reflective pricing requires smart meter data. Currently 60% of residential ICPs and 57% of general ICPs on our network have communicating smart meters. To increase the availability of cost-reflective pricing to all consumers, we need retailers to finish their smart meter rollouts, MEPs to upgrade their mesh networks and meter communications to decrease the number of meters that are out of communication range.

Retailer data

We implemented TOU pricing five years ago for most residential and general consumers. Currently we have 59% of ICPs on TOU pricing and consider sufficient time has been afforded for retailers to adapt their systems to provide us with time-sliced data (i.e. consumption data in a peak/off-peak format) for billing purposes, and to enter into agreements with metering equipment providers for the supply of data. As such, the only exceptions from TOU pricing will be ICPs which have a legacy meter, or a non-communicating smart meter installed, on legacy pricing plans.

6. Pricing Roadmap and Strategy

In 2019, the Authority 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.'*[3]

We have been on a transition pathway to reform our prices, balancing the need to meet the Authority's pricing expectations with regard for the impact pricing reform has on our consumers.

Our pricing roadmap (see Appendix 1) sets out how we are going to implement our strategy.

6.1 Option identification

End Consumers

In 2025, Electra surveyed end-users within the network and 82% of respondents indicated they were 'very' or 'quite satisfied' with the reliability of supply. Only 4% of respondents indicated a willingness to consider trading off a lower level of reliability in return for lower bills.

Our network has seen an uptake in LED lighting, heat-pumps, EVs and solar panel installations. From our 2025 survey, around 66% of respondents had LED lighting and 10% an EV. Around 7% of the people surveyed had solar panels and 3% battery storage. Concerns around high upfront costs, and satisfaction with the status quo, mean that those without these technologies are by in large unlikely to consider purchasing them within the next twelve months.

These findings align with international and local research which has shown that while consumers are interested in lower cost electricity, they do not want to have to think about how they use it or assess the investment trade-off. To ensure the lights come on when they're needed, pricing structures must be understandable and actionable (i.e. the consumer can respond to signals when they are needed). Consumers must be brought along the journey for any pricing reform, with the benefits to them clearly evidenced.

Retailers

Implementing cost-reflective prices requires us to coordinate our approach with retailers, who provide us with the data required for billing and pass through our prices to end consumers. The broad variety of competing retailers that operate within our network means a wide range of price options are available for varying customer needs. Our 2025 survey identified that less than half of respondents have considered switching retailer and less than 3% had actually switched over the previous twelve months.

Consultation with retailers in late 2025 identified that our existing shoulder price option was very hard to administer, making it difficult to identify the best solution for their customers. Retailers are also on a transition pathway to more cost-reflective pricing and simplified structures will allow different retailers to trial alternative solutions with greater certainty around the network cost implication.

[3] Electricity Authority, Distributors' Pricing 2019 Baseline Assessment, 19 November 2019, paragraph 1.1.

Transition pathway

To manage the impact of 'winners and losers', as we transition to more cost-reflective prices, consumer impacts must be considered. As new rates are introduced and legacy rates retired, changes must be signalled to users and where the consumer impact is significant, a transition pathway developed. This provides consumers with the time to adjust their behaviour and identify more efficient investment options.

6.2 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:

1. Signal the economic costs on our network; and
2. Where a revenue shortfall occurs, recover that shortfall in a way that least distorts network use.

6.3 Pricing structures

6.3.1 Consumer groups

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 98% of connections and 69% 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 and industrial loads. In contrast to the mass market, most large industrial loads have half-hourly metering and much higher consumption levels (ranging from 40,000kWh pa to more than 3GWh pa). Large commercial and industrial 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 Commercial and Industrial (C&I) User consumer groups incorporate signals that enable consumers to achieve a lower overall cost of supply by shifting consumption to off-peak periods where they can and by offering us interruptible load to manage the network demands. This aligns our pricing incentives to the cost of network capacity and capacity utilisation.

Our consumer groups were assessed in 2023 and remain largely unchanged. The groups continue to serve a range of different connection needs and align to the groups used in neighbouring networks. As the LFC regime is phased out, we obtain more detailed connection information, and technological advancements change the needs of our network users, we expect our consumer groups will also evolve. From 2026 we will segment our C&I group as shown in Table 1.

Table 1: Consumer Groups

Consumer Group	Target Consumer
Low User	A primary-residence connection expected to consume 8,000kWh or less per annum.
Standard	A residential or small business connection expected to consume between 8,000-40,000kWh per annum.
Small C&I	A business connection expected to consume more than 40,000kWh per annum.
Medium C&I	A business connection expected to consume more than 100,000kWh per annum.

Large C&I	A business connection expected to consume more than 400,000kWh per annum.
Extra Large C&I	A business connection expected to consume more than 1,500,000kWh per annum.
Individual	Available on request to end-consumers that require non-standard pricing. This is currently limited to Council streetlighting
Unmetered	A low-capacity fixed connection, without a meter measuring consumption, but with a predictable annual energy usage.
Export	For those who are generating electricity on their premises and exporting some or all of this into Electra's distribution network.

Note that consumer groupings are not exclusive. For example, we have export customers that are within the standard user group.

6.3.2 Charge types

From 2022, we adopted TOU pricing for our Low and Standard User consumer groups better to signal the economic costs of future capacity investments. In transitioning to TOU pricing, we contrasted the relative benefits of this solution against peak demand and capacity-based tariff options.

Time of Use (TOU) pricing

We selected TOU as our preferred cost-reflective pricing methodology following feedback that this option was preferred by consumers and retailers, that it was the easiest option for consumers to understand and respond to, and for retailers to implement.

It enables us to increase prices at times when there is congestion on the network and reduce them at times when there is plenty of capacity. This sends a price signal to transfer load outside of congestion periods and incentivises growth in consumption at times when there is no incremental cost for us to deliver the additional energy.

For example, it enables us to target setting the off-peak price at (or close to) zero, because there is no incremental cost for us to deliver energy at that time. Conversely higher prices are set during peak period, which signal the likely need for network upgrades to manage the congestion. Consuming during peak, and paying the addition cost, allows us to fund network upgrades, or shift your consumption, which will result in both you and us saving money.

Disaggregating peak and off-peak consumption helps us better reflect the economic costs associated with future capacity investment.

From April 2026, TOU pricing will be mandatory for all connections on our network with a communicating smart meter. Exemptions from TOU have previously been provided to retailers in the process of updating their systems and metering arrangements to enable them to supply us data for TOU billing purposes, or when there was a stated customer preference for uncontrolled pricing. Now that retailers are also required to offer TOU, we expect the transition will be accelerated. We also note that this pricing only relates to how we charge the retailer; retailers can determine what and how they charge their customers.

Demand based pricing

Demand based pricing was discounted as an option as it is not easy for consumers to understand or respond to. Without costly in-home upgrades, consumers are unable to understand demand at a specific point in time and meters generally do not collect capacity demand data, or measure consumption in intervals more frequently than 30 minutes. 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.

Capacity based pricing

Installed capacity pricing is also unsuitable at this point in time. Most consumers are not aware of the capacity of their connection, which was designated prior to their occupation. Optimising the capacity of a connection would be cost prohibitive to most our users and we don't hold complete data on installed fuse sizes. While we are building our understanding of the fused capacity of our Commercial and Industrial connections, it will be expensive and impractical to build this knowledge base for our entire network.

6.4 Pricing methodology

6.4.1 Drivers of the cost of supply

We have followed the allocation approach of other network businesses to determine the most appropriate allocator for apportioning target revenue by consumer group. We use three drivers across the different costs of supply.

Number of ICPs

Where we receive costs, such as rates and levies, based on the number of ICPs, we allocate the cost of supply based on ICP count. Similarly ICP count is used for return on investment and tax because the discount is paid at the ICP level. ICP count can be an inefficient allocator for other costs because large users may contribute significantly to peak and overall demand, yet represent only a single connection. These consumers, and their associated assets, demand significantly more dedicated network engineering, operations and management resource and support than an average consumer or business.

Consumption volume

Consumption was considered an efficient allocator for support costs, depreciation and transmission charges as large consumers with higher consumption are most adversely affected by low reliability. MWh is however inappropriate for most of our costs as we do not sell energy across our network and it does not recognise the efficient use of electricity in unconstrained period.

Average capacity/utilisation

Capacity and asset utilisation was not adopted because we have low oversight on the capacity of most of our connections. As we build out our understanding of the capacity of individual connections within our network, our sophistication with using this as a cost allocator will improve.

6.4.2 Phased implementation

Electra has designed its methodology with regard to the Authority's Practice Note and focus areas. We determine our target revenue and seek to recover target revenue via the least distorting charges.

A phased implementation approach is employed to mitigate the impact on consumers as we are cognisant of the impact of price shocks from changing prices too quickly. Clear signalling of how prices are changing, and how prices will become more cost-reflective, allows consumers to make more economic investment decisions in alternative technologies as their assets reach end of life. Signalling through a transition pathway ensures we minimise the impact on consumers when prices change.

There are two types of price changes which require phasing:

1. **Fixed/variable prices:** as a proportion of a consumer's bill, fixed prices need to increase and variable prices decrease, to reflect the fixed cost nature of the service we provide. This enables consumers to tap unutilised capacity in the network at little to no additional cost. As we transition out of the LFC regulation, we must balance the gap between our Standard and Low User daily fixed charge.
2. **Peak/off-peak prices:** Our strategy is for off-peak prices to approach nil, reflecting our minimal incremental costs to deliver electricity during periods where there is no congestion on the network. As fixed prices increase over time, off-peak prices may be able to further reduce, and peak prices reduce (or increase at a much slower rate).

6.5 Progress for April 2026

We have continued to advance our use of the Cost of Supply model with better understanding of how connections have, and should be, assigned to consumer groups.

The move to mandatory TOU pricing for all connections with a communicating smart meter means that we expect many consumers will be migrated from the uncontrolled options which have had a higher effective rate. We will be working with retailers to migrate affected users.

We have also segmented the C&I pricing category into four sizes to reflect the different cost to serve for a user that consumes 40,000kWh per annum compared to one consuming more than 2,000,000kWh per annum.

Despite a sharp increase in their daily fixed charge, connected consumers with extremely high levels of consumption are expected to be better off through relatively lower variable charges. Retailers will also be involved in helping us to segment the C&I users.

Daily fixed charges for all consumer groups have increased in line with our strategy to increase our cost recovery from fixed price components and reduce variable prices over time. This decision was made to increase the reflectivity of our prices after holding them constant over previous years.

From April 2026, we have also removed the shoulder period from our TOU options. Off-peak prices for all categories have increased because the eight trading periods per day that had been recovered using the shoulder price will now be treated as off-peak. Similarly, weekends will now also be treated as off-peak. This change will reduce the confusion for end-users around when it is most effective to shift their consumption.

In line with regulatory change, a rebate has been introduced for distributed generation that exports during the peak periods in winter. The rate is based on the Long Run Marginal Cost of Supply with an adjustment that ensures we can provide an enduring signal for the value of electricity injected into our network.

By incorporating these changes, we have sought to manage the impact to existing connections and ensure the pivot point between groups is appropriately signalled to encourage users to be placed on the right network charges.

6.6 Next steps

We continue to progress on our Pricing Roadmap, having made good progress already. We annually review our pricing structure to improve cost reflectivity and keep up with market developments. We are also looking at guidance from the Authority and industry developments both in New Zealand and globally.

Midway through 2026 we intend to conduct the network studies that will allow us to review our loss factor. While there have not been any material changes in our network, this work was last completed five years ago so should be revisited.

Through 2026 we also intend to gather capacity information on our commercial and industrial users to improve the way we segment this pricing category and introduce a capacity charge. As we are now in the final year of phasing out Low User Fixed Charge regulations, we will also look to implement an option for low-capacity connections.

As we move to better reflect the fixed costs of our network through prices, we also intend to build our understanding of the Long-Run Marginal Cost to upgrade our network or defer investment. We monitor the cost to complete network investment and the nature of constraints that can accelerate the need for upgrades. As this knowledge evolves, we improve our ability to set peak prices based on the Long-Run Marginal Cost.

While we have implemented TOU, we don’t see this as the end point for the evolution of pricing. However, we expect that further change will be triggered by technological development and new markets, which enable electricity consuming devices to respond in real time. We will look to monitor the adoption and development of automated demand management technology as we see this as a potential enabler to real time demand response.

7. Network Pricing for 1 April 2026

Further information on the setting of prices for 1 April 2026 is in Electra's Pricing Schedule.

7.1 Approach

Electra's pricing methodology is designed to support an efficient level of investment in our network for the long-term benefit of consumers and to comply with the Authority's pricing principles (Appendix 2). Prices are set to signal the underlying costs of supplying services, allowing consumers to make efficient decisions about how they connect to, and use, our network. This allows Electra to plan and operate our network assets safely, efficiently, and reliably.

7.2 Target revenue

Electra calculates its target annual revenue using the Commerce Commission's building block model (BBM), to benchmark its returns as if it were subject to price-quality regulation.

The model results in target revenue of $70.6m, an increase of $7.9m on prior year target revenue

Table 2: Revenue Components ($000s)

Type	Component	Apr-25	Apr-26	Change	
Distribution	Operating Expenditure	26,883	27,659	776	3%
	Depreciation	12,381	13,386	1,005	8%
	Regulatory tax allowance	2,484	3,392	908	37%
	Return on investment (ROI)	8,871	12,113	3,242	37%
Pass through	Transmission	11,528	13,490	1,962	17%
	Rate & Levies	513	552	39	8%
Total		**62,660**	**70,591**	**7,931**	**13%**

This revenue is shown gross of (or including) the discount to be paid during the year, which is $9.15m (i.e. the target revenue net of the discount will be $61.45m). The discount is included in the ROI for the purposes of applying the BBM framework.

7.3 Identify pricing regions

The second step in the pricing process is to identify whether there are any substantial differences in the economic costs to serve across pricing regions. There are a variety of ways in which pricing regions could be determined, including by connection type (e.g. rural vs urban) or grid exit point (GXP).

We do not consider that regional pricing is appropriate for our network, at this time, as the cost to serve consumers in each GXP and connection type is roughly equivalent. We will investigate establishing pricing regions in the future to address network constraints if appropriate.

Our network area is compact, with rural areas relatively close to urban centres, meaning there is minimal difference in the length of circuits and no differentiation in service quality.

The cost to serve consumers from our Paraparaumu GXP is around 59% of total target revenue, which corresponds to the around 61% of total ICPs connected in the area and 58% of annual network demand. While there is greater network congestion observed in our Mangahao GXP region, we are currently able to use load management solutions to manage constraints.

7.4 Determine Consumer Groups

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. We have divided our consumers into five groups based on the type of connection, their annual consumption and their metering configuration. Price category codes roll up into four consumer groups:

- Low user
- Standard
- Commercial & Industrial (C&I)
- Individual

For April 2026, analysis was conducted to ensure consumers were effectively allocated to the right consumer group. In allocating to consumer group, we reviewed every ICP's annual consumption ANZSIC code and meter category.

7.5 Allocating Revenue to Consumer Groups

The revenue to be recovered is $70.59m excluding GST.

When setting prices, we do so with the objectives of fairness, distributing the agreed discount to consumers, sending appropriate price signals to consumers, avoiding bill shock, and aligning with the Authority's Pricing Principles. We set prices to recover the total target revenue over the pricing year.

We use our Cost of Supply model to first allocate target revenue to consumer groups. The allocators reflect how the different consumer groups drive the cost components.

Table 3: Proportion of cost driver by Consumer Group for the April 2026 pricing year

Consumer Group	No. of ICPs		Consumption (MWh)		Installed Capacity (kVA)		Asset Utilisation (kW)	
Low Users	31,658	67%	137,350	32%	221,606	63%	225,412	63%
Standard	14,995	32%	157,235	37%	104,965	30%	106,768	30%
C&I	722	2%	131,789	31%	24,465	7%	24,885	7%
Individual	2	0%	1,122	0%	2	0%	2	0%

Our Cost of Supply model then allocates costs by Consumer Group, based on the most appropriate driver of that network cost.

Table 4: Cost allocation by driver ($000s)

Cost Category	Cost Component	Cost Driver	Cost ($000s)
Operating Expenditure	Service Interruptions and Emergencies	No. of ICPs	$2,672
	Vegetation Management	Line Length	$2,258
	Routine and Corrective Maintenance	Consumption	$1,871
	Asset Replacement and Renewal	Consumption	$792
	System Operations and Network Support	Consumption	$7,933
	Business Support	Consumption	$12,133
Depreciation	Depreciation - Network Assets	Attributable Cost	$10,689
	Depreciation - Non-network Assets	Attributable Cost	$2,697
Rates & Levies	Council Rates	Attributable Cost	$300
	Commerce Act Levies	No. of ICPs	$39
	Electricity Authority Levies	Attributable Cost	$173
	Utilities Disputes Levies	Consumption	$37
	FENZ Levies	No. of ICPs	$4
Transmission	Connection Charge	Attributable Cost	$2,277
	Benefit-based charges (BBC)	Attributable Cost	$1,729
	Residual Charge	Attributable Cost	$8,819
	Transitional Cap	Attributable Cost	$6
	New investment charges	Attributable Cost	$659
Regulatory Tax Allowance	Regulatory Tax Allowance	Attributable Cost	$3,392
Return on Investment	Return on Investment	Attributable Cost	$12,113
Total Cost to Serve			**$70,591**

Through our price review process, we also identified a number of large Commercial and Industrial Users that were contributing a large share of variable revenue when their cost to supply is largely fixed. To better reflect the use of the network, we will transition to using capacity based charging for C&I consumers. Segmentation of these consumers, based on consumption, is the first stage of this process.

Our pricing strategy aims to set efficient and appropriate prices. Better segmentation of ICPs, to more appropriate consumer groups, will ensure we are better placed to achieve our pricing strategy objectives longer term. This has resulted in a material change year-over-year in the proportion of our target revenue allocated across the consumer groups.

Table 5: Target revenue by consumer group

Consumer Group	April 2025		April 2026	
	($000s)	*Proportion*	*($000s)*	*Proportion*
Low User	32,579	52%	*36,828*	*52%*
Standard	17,344	28%	*23,844*	*34%*
Small C&I	11,897	19%	*2,273*	*3%*
Medium C&I			*3,048*	*4%*
Large C&I			*2,677*	*4%*
X-Large C&I			*1,841*	*3%*
Individual	840	1%	*80*	*0%*
Total	**62,660**		***70,591***	

7.6 Developing prices for consumer groups

The expected revenue recovered from each consumer group cannot match the target revenue without introducing unreasonable shocks to consumers' bills.

Over our pricing roadmap we have sought to ensure our prices are free from cross-subsidisation. This progress must however be balanced against the impact on existing users and adhere to regulatory requirements.

Table 6: Target against forecast revenue by consumer group

Consumer Group	Revenue		Variance	
	Target	*Forecast*	*($000s)*	*%*
Low User	36,828	31,873	*(4,955)*	*(13%)*
Standard	23,844	27,711	*3,867*	*16%*
Small C&I	2,273	2,853	*580*	*26%*
Medium C&I	3,048	3,420	*372*	*12%*
Large C&I	2,677	2,660	*(18)*	*(1%)*
X-Large C&I	1,841	1,744	*(97)*	*(5%)*
Individual	80	331	*251*	*312%*
Total	**70,591**	**70,591**		

The LFC regime continues to limit the revenue we can recover from our Low User group and how we design the tipping point to the Standard user and then each of the C&I bands. Removing this cross-subsidisation would have created a substantial bill shock to connections already in our Low User and Industrial groups, which we have chosen to continue to smooth over the next year.

With more cost reflective prices from April 2026, we are better placed to work towards removing the cross-subsidisation from April 2027 when the LFC has been fully phased out.

Both the Low User and Standard Consumer groups offer the choice between General or TOU pricing. The Commercial and Industrial group have TOU pricing with an uncontrolled rate available by exemption for legacy connections without a communicating smart meter.

7.6.1 General Pricing

General pricing for Low User and Standard includes two variable options:

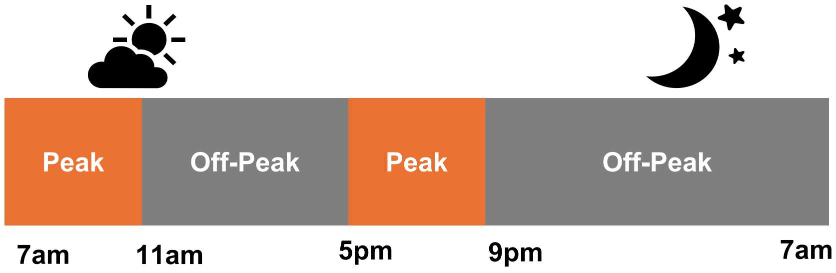
- **Uncontrolled**
  A flat rate that applies 24/7, effective for those consumers who have little interest or ability to change their consumption patterns. A higher price is charged because there is no price signal and unconstrained consumption drives more of our future costs.
- **Controlled**
  A price 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 lower than the Uncontrolled rate.

7.6.2 TOU pricing

TOU pricing for Low Users and Standard includes four variable options depending on the time of consumption and meter.

- **Peak**
  Aimed to discourage consumption of electricity in the period between 7am-11am and 5pm-9pm on weekdays by sending a strong price signal.
- **Off-Peak**
  Aimed to encourage all consumption of electricity that is not time critical to be deferred to the off-peak period between 11am-5pm and 9pm-7am weekdays or anytime in the weekend. Consumers are rewarded with a lower rate.
- **Controlled**
  A price that rewards consumers for giving us control of their hot water cylinders. Electra can control the hot water load for up to 4 hours a day and, in return, charge consumers a price lower than the Peak rate.
- **Export Rebate**
  A price that rewards consumers for providing any excess generation, beyond requirements of the premise, to the wider network during the constrained peak periods in the winter months (April to September inclusive).

Figure 1: Time of Use effective hours (weekday only)



7.6.3 Other pricing

Commercial and Industrial pricing is also effective over the two TOU periods, with a nil rated capacity charge. Capacity charges are included to signal the intended direction for this pricing category, which will increase as data becomes available.

Unmetered pricing offers a variable rate for low capacity (>1kVA) connections with predictable annual energy usage, but without a meter measuring consumption. For streetlighting connections, a daily fixed rate is offered per fitting with a nil rate for consumption.

Export pricing is zero rated to recognise the contribution distributed generation connections can make by injecting energy during periods where the network is constrained. Outside of the conditions exclusive to the export rebate, we neither charge, nor pay, distribution generation for variable injection within our network.

Individual pricing is available on request to end-consumers that require non-standard pricing.

The terms and conditions for the supply of electricity distribution services are provided by the Default Distributor Agreement (DDA) we have with all retailers. If a consumer was to approach us with connection needs outside the terms of the DDA, we can negotiate non-standard agreement directly with the consumer.

Electra has one network user on a non-standard agreement. KCE Mangahao is embedded within our network, on agreed bilateral terms reviewed periodically. From 1 April 2026 KCE is expected to be on a standard connection agreement for distributed generation.

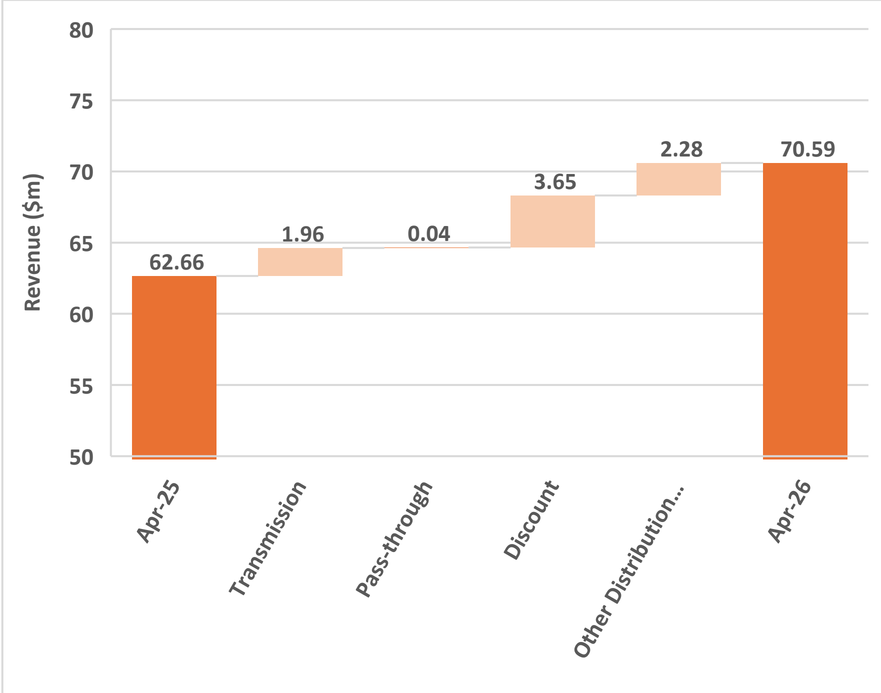
7.7 Changes to our pricing from 1 April 2026

The Pricing Schedule for 1 April 2026 sets out the specific prices for consumers connected to our network. The prices reflect a total average increase in forecast revenue of 13% or $7.9m compared to last year.

Electra has experienced a $2.0m increase in transmission and other pass-through costs. Electra has also chosen to increase the discount amount paid to connected businesses and households by $3.6m. The other costs associated with Electra running and investing in the network have increased the revenue requirement by a further $2.3 million.

Electra has again completed a significant review of the profile of ICPs connected to our network, to ensure the right pricing incentives are in place for each consumer group. As result of this, Electra is expecting to see significant movement in the mix of ICPs within each pricing category from mandating TOU pricing and segmenting the Commercial and Industrial group. These changes will mean that for many of our consumers they will move to prices with lower effective annual charges than if they'd remained in their prior pricing category.

Figure 2: What makes up the changes for prices from April 2026 compared to 2027



This year we have further simplified the pricing schedule by removing the shoulder option. We also sought to collect more revenue through fixed charges to improve the reflectivity of our prices, specifically signalling the unavoidable costs to maintain and operate our network, regardless of the level of consumption.

We are working with retailers to propose they migrate consumers to more suitable pricing categories. After adjusting for the proposed migration, as well as migrations that have already occurred, there has been a marked change in expected average consumption and revenue from each group.

With the removal of the shoulder period, there has been a reduction in the differential between the peak and off-peak rate. The Long Run Marginal Cost (LRMC) associated with system investment that could be avoided by deferred demand has been calculated at $205/kW. Peak prices apply over 2,086 hours of the year (8 hours per day x 5/7 days per week x 365 days per year). This creates a differential of $0.10/kWh which was used for pricing.

The export rebate, paid for net injection during peak period within winter has been calculated at $0.06/kWh. This is based on the LRMC of $205/kW and applying over 1,046 hours of the year (8 hours per day x 5/7 days per week x 183 days per year) with a 69% adjustment factor to allow for uncertainty around how net export will impact future network investment and smooth the price signal over the longer term.

Table 7: Revenue breakdown April 2025

Consumer Group		Average Bill (pa)	ICPs	Average Consumption (kWh pa)	Revenue Recovered ($000s pa)
Low User	General	$879	15,765	4,154	$13,859
	TOU	$840	18,343	4,308	$15,416
	Total	**$858**	**34,108**	**4,237**	**$29,275**
Standard	General	$1,959	5,050	12,814	$9,889
	TOU	$1,686	7,361	12,291	$12,406
	Total	**$1,797**	**12,411**	**12,504**	**$22,295**
Commercial & Industrial		**$13,682**	**740**	**175,185**	**$10,127**
Individual			2		$963
Total		**$1,326**	**47,259**	**9,106**	**$62,660**

Table 8 Revenue breakdown April 2026

Consumer Group		Average Bill (pa)	ICPs	Average Consumption (kWh pa)	Revenue Recovered ($000s pa)
Low User	General	$1,017	7,202	4,217	$7,324
	TOU	$1,004	24,456	4,374	$24,548
	Total	**$1,007**	**31,658**	**4,339**	**$31,873**
Standard	General	$1,864	4,038	9,623	$7,525
	TOU	$1,842	10,957	10,804	$20,186
	Total	**$1,848**	**14,995**	**10,486**	**$27,711**
Commercial & Industrial	Small	$6,527	437	61,957	$2,853
	Medium	$15,409	222	183,941	$3,420
	Large	$52,142	51	738,098	$2,660
	X-Large	$145,352	12	2,186,317	$1,744
	Total	**$14,787**	**722**	**182,533**	**$10,677**
Individual			2		$331
Total		**$1,490**	**47,375**	**9,024**	**$70,591**

Compared to the rates we published for April 2025, the lines component of the average user's electricity bill is expected to increase by 13%, in line with the overall revenue uplift. Around 8,000 consumers (over 17% of total ICPs) being expected to migrate from General to TOU pricing, which has a lower effective average bill, on a like-for-like consumption basis. The segmenting of the Commercial and Industrial consumer group combined with a shift toward greater penetration of TOU pricing means that the average increase across all consumer groups is around 15% for April 2026, assuming the consumption profile remains constant.

Table 9: Pre-discount weighted average change in line charges

Consumer Group		Average Consumption (kWh pa)	Weighted Average Annual Bill (pre-discount) *Apr-25*	*Apr-26*	*Change*	
Low User	General	4,217	$885	$1,017	*$132*	*15%*
	TOU	4,374	$848	$1,004	*$156*	*18%*
	Total	**4,339**	**$857**	**$1,007**	***$150***	***18%***
Standard	General	9,623	$1,677	$1,864	*$186*	*11%*
	TOU	10,804	$1,556	$1,842	*$286*	*18%*
	Total	**10,486**	**$1,589**	**$1,848**	***$259***	***16%***
Commercial & Industrial	Small	61,957	$5,705	$6,527	*$822*	*14%*
	Medium	183,941	$14,440	$15,409	*$969*	*7%*
	Large	738,098	$52,443	$52,142	*($301)*	*(1%)*
	X-Large	2,186,317	$151,504	$145,352	*($6,152)*	*(4%)*
	Total	**182,533**	**$14,116**	**$14,787**	***$672***	***5%***
Total		**9,024**	**$1,290**	**$1,483**	***$193***	***15%***

As Electra moves to capacity charging for the Commercial and Industrial User group, we have chosen to allocate a fixed discount amount against each pricing category, rather than being based on a daily fixed and variable rate. This should ensure there is a more consistent discount paid to users in proportion to their average annual charges. Where a user changes category or is active for a portion of the year to 31 January, payment will be made based on the number of days an ICP is active within each pricing category. The amount allocated for discount payments has increased from $5.50m to $9.15m (excluding GST).

After adjusting for the change in discount payments, the change in the weighted average annual bill post-discount reduces to 10% compared to 15% pre-discount.

Table 10: Discount payment by pricing category

Consumer Group		Discount Amount per ICP from April 2026 *Per Annum*	*Per Day*	Number of ICP	Expected total discount all ICPs ($000)
Low User	General	$185	$0.5068	7,202	$1,332
	TOU	$185	$0.5068	24,456	$4,524
Standard	General	$185	$0.5068	4,038	$747
	TOU	$185	$0.5068	10,957	$2,027
Commercial & Industrial	Small	$431	$1.1808	437	$188
	Medium	$778	$2.1315	222	$172
	Large	$2,086	$5.7151	51	$106
	X-Large	$4,070	$11.1507	12	$49
Total					**$9,147**

Table 11: Post-Discount weighted average change in line charges

Consumer Group		Average Consumption (kWh pa)	Weighted Average Annual Bill (post discount) *Apr-25*	*Apr-26*	*Change*	
Low User	General	4,217	$804	$832	*$28*	*3%*
	TOU	4,374	$766	$819	*$53*	*7%*
	Total	**4,339**	**$775**	**$823**	***$47***	***6%***
Standard	General	9,623	$1,557	$1,679	*$121*	*8%*
	TOU	10,804	$1,426	$1,657	*$231*	*16%*
	Total	**10,486**	**$1,462**	**$1,663**	***$201***	***14%***
Commercial & Industrial	Small	61,957	$5,202	$6,096	*$893*	*17%*
	Medium	183,941	$13,048	$14,631	*$1,583*	*12%*
	Large	738,098	$47,005	$50,056	*$3,051*	*6%*
	X-Large	2,186,317	$135,494	$141,282	*$5,788*	*4%*
	Total	**182,533**	**$12,733**	**$14,072**	***$672***	***11%***
Total		**9,024**	**$1,174**	**$1,290**	***$116***	***10%***

Because of the segmentation of the Commercial and Industrial User Group and the increase in the Low User daily fixed charge rate, the target revenue split by fixed components has increased to around 33% of all revenue. We expect this to increase in future years as the LFC restrictions are removed and we bring in capacity related charges for Commercial & Industrial Users.

Table 12: Breakdown of fixed and variable charges

Consumer Group		April 2025			April 2026		
		ICPs	*Fixed*	*Variable*	*ICPs*	*Fixed*	*Variable*
Low User	General	15,765	31%	69%	7,202	32%	68%
	TOU	18,343	33%	67%	24,456	33%	67%
Standard	General	5,050	32%	68%	4,038	39%	61%
	TOU	7,361	38%	62%	10,957	40%	60%
Commercial & Industrial	Small	740	11%	89%	437	28%	72%
	Medium				222	18%	82%
	Large				51	7%	93%
	X-Large				12	4%	96%
Individual		-	84%	16%		49%	51%
Total		**47,259**	**31%**	**69%**	**47,375**	**33%**	**67%**

From April 2026, Electra is making changes to the way we price new connections on our network. Previously any extensions to our network that were made at the request of a customer were funded by them then vested back to Electra for ongoing operation and maintenance. While this approach may remain suitable for many new connection requests, we intend to adjust our approach toward determining an appropriate connection charge in line with regulatory changes. The capacity costing rates that will be used for reconciliation purposes when quoting for new connections are as shown in Table 13.

The system-wide capacity rate was calculated at $3,793/kVA for the year beginning April 2026. The capacity rate is based on an LRMC of $380/kW per annum in nominal terms for system growth capex, with a capacity to demand ratio of 70%.

Because, at this point in time, there is not assessed to be a material difference in the capacity cost to invest in alternative network zones, a flat rate is applied across the network depending on the tier of the network for which investment the new connection will utilise. The system-wide capacity rate has been allocated across network tiers in proportion to the value of the replacement cost of assets in each network tier as reported in Electra's Regulatory Asset Base (RAB).

Table 13: Network Capacity Costing Rates from April 2026

	Network Tier				
	Low voltage mains	Distribution substation	High-voltage feeder	Zone substation	Sub-transmission line
Rate per kVA	$919	$518	$1,345	$581	$431

Table 14: Composition of April 2026 prices and change in rate

Consumer Group		Pricing Option	Code	Unit	April 2025 Rate	Distribution	Pass-through	Transmission	April 2026 Rate	Post Discount Rate	Change in Rate	Estimated Users
Low User	***General***	Fixed daily	LGF	$/con/day	0.7500	0.4939	0.0319	0.3742	**0.9000**	0.3932	***20%***	**7,202**
		Anytime	LGUC	$/kWh	0.1584	0.1706	-	-	**0.1706**	0.1706	***8%***	
		Controlled	LGCN	$/kWh	0.0842	0.1301	-	-	**0.1301**	0.1301	***55%***	
	TOU	Fixed daily	LF	$/con/day	0.7500	0.4939	0.0319	0.3742	**0.9000**	0.3932	***20%***	**24,456**
		Off-Peak	LOP	$/kWh	0.0534	0.1176	-	-	**0.1176**	0.1176	***120%***	
		Peak	LPK	$/kWh	0.1897	0.2176	-	-	**0.2176**	0.2176	***15%***	
		Shoulder	-	$/kWh	0.1438	NA	-	-	**NA**	NA	***-***	
		Controlled	LUC	$/kWh	0.0842	0.1301	-	-	**0.1301**	0.1301	***55%***	
		Export Rebate	LXR	$/kWh	NA	-0.0600			**-0.0600**	-0.0600	***-***	
Standard User	***General***	Fixed daily	SGF	$/con/day	1.7423	1.0653	0.0321	0.9026	**2.0000**	1.4932	***15%***	**4,038**
		Anytime	SGUC	$/kWh	0.1132	0.1205	-	-	**0.1205**	0.1205	***6%***	
		Controlled	SGCN	$/kWh	0.0390	0.0800	-	-	**0.0800**	0.0800	***105%***	
	TOU	Fixed daily	SF	$/con/day	1.7423	1.0653	0.0321	0.9026	**2.0000**	1.4932	***15%***	**10,957**
		Off-Peak	SOP	$/kWh	0.0082	0.0675	-	-	**0.0675**	0.0675	***723%***	
		Peak	SPK	$/kWh	0.1445	0.1675	-	-	**0.1675**	0.1675	***16%***	
		Shoulder	-	$/kWh	0.0986	NA	-	-	**NA**	NA	***-***	
		Controlled	SCN	$/kWh	0.0390	0.0800	-	-	**0.0800**	0.0800	***105%***	
		Export Rebate	SXR	$/kWh	NA	- 0.0600			**-0.0600**	-0.0600	***-***	
Unmetered		Unmetered	U	$/kWh	0.1500	0.1500	-	-	**0.1500**	0.1500	***0%***	
		Lighting Fixed	LGT	$/fitting/day	0.2500	0.2500	-	-	**0.2500**	0.2500	***0%***	
Export		Small scale distributed generation	EX	$/kWh	-	-	-	-	**-**	-	***-***	

Table 14 continued: Composition of April 2026 prices and change in rate

Consumer Group		Pricing Option	Code	Unit	April 2025 Rate	Distribution	Pass-through	Transmission	April 2026 Rate	Post Discount Rate	Change in Rate	Estimated Users
Commercial & Industrial User	***Small***	Fixed daily	CISF	$/con/day	4.1230	0.3991	0.0314	4.5695	**5.0000**	3.8192	***21%***	**437**
		Off-Peak	CISOP	$/kWh	0.0086	0.0401	-	-	**0.0401**	0.0401	***366%***	
		Peak	CISPK	$/kWh	0.1100	0.1401	-	-	**0.1401**	0.1401	***27%***	
		Shoulder	-	$/kWh	0.0717	NA			**NA**	NA	***-***	
		Uncontrolled	CISUC	$/kWh	NA	0.0901			**0.0901**	0.0901	***-***	
		Capacity	CISC	$/kVA/day	-	-	-	-	**-**	-	***-***	
	Medium	Fixed daily	CIMF	$/con/day	4.1230	-8.5625	0.0309	16.0316	**7.5000**	5.3685	***82%***	**222**
		Off-Peak	CIMOP	$/kWh	0.0086	0.0309	-	-	**0.0309**	0.0309	***259%***	
		Peak	CIMPK	$/kWh	0.1100	0.1309	-	-	**0.1309**	0.1309	***17%***	
		Shoulder	-	$/kWh	0.0717	NA	-	-	**NA**	NA	***-***	**51**
		Uncontrolled	CIMUC	$/kWh	NA	0.0809			**0.0809**	0.0809	***-***	
		Capacity	CIMC	$/kVA/day	-	-	-	-	**-**		***-***	
	Large	Fixed daily	CILF	$/con/day	4.1230	-54.0729	0.0314	64.0415	**10.0000**	4.2849	***143%***	**51**
		Off-Peak	CILOP	$/kWh	0.0086	0.0286	-	-	**0.0286**	0.0286	***233%***	
		Peak	CILPK	$/kWh	0.1100	0.1286	-	-	**0.1286**	0.1286	***17%***	
		Shoulder	-	$/kWh	0.0717	NA			**NA**	NA	***-***	
		Uncontrolled	CILUC	$/kWh	NA	0.0786			**0.0786**	0.0786	***-***	
		Capacity	CILC	$/kVA/day	-	-	-	-			***-***	
	Extra Large	Fixed daily	CIXF	$/con/day	4.1230	-177.3961	0.0301	192.3660	**15.0000**	3.8493	***264%***	**12**
		Off-Peak	CIXOP	$/kWh	0.0086	0.0273	-	-	**0.0273**	0.0273	***217%***	
		Peak	CIXPK	$/kWh	0.1100	0.1273	-	-	**0.1273**	0.1273	***16%***	
		Shoulder	-	$/kWh	0.0717	NA	-	-	**NA**	NA	***-***	
		Uncontrolled	CIXUC	$/kWh		0.0773			**0.0773**	0.0773	***-***	
		Capacity	CIXC	$/kVA/day	-	-	-	-	**-**		***-***	
Unmetered		Unmetered	U	$/kWh	0.1500	0.1500	-	-	**0.1500**	0.1500	***0%***	
		Lighting Fixed	LGT	$/fitting/day	0.2500	0.2500	-	-	**0.2500**	0.2500	***0%***	
Export		Small scale distributed generation	EX	$/kWh	-	-	-	-	**-**	-	***-***	

8. Further information

We welcome your feedback and any questions you may have on this Pricing Methodology.

You can contact Electra by email to pricing@electra.co.nz.

8.1 Options for our Consumers

We recognise the impact our prices have on consumers, our role in the energy system and the services other agencies can provide to ensure your needs are met.

As we do not have a direct relationship with our connected consumers, we encourage users to have a good relationship with their electricity retailer. There are numerous retailer offerings in the market, providing consumers with a range of options to suit their needs.

POWERSWITCH by 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.

- MBIE are supporting low electricity-use households finding it hard to pay their power bills as the LFC tariff regulations are phased out through the Power Credits Scheme.

- EECA's Warmer Kiwi Homes scheme will contribute to up to 80% of the total cost of ceiling and underfloor heating, and an approved heater for low-income homeowners.

- Work and Income also provide extra payments for beneficiaries to help with energy costs from May to October every year, through their Winter Energy Payment scheme.

8.2 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.

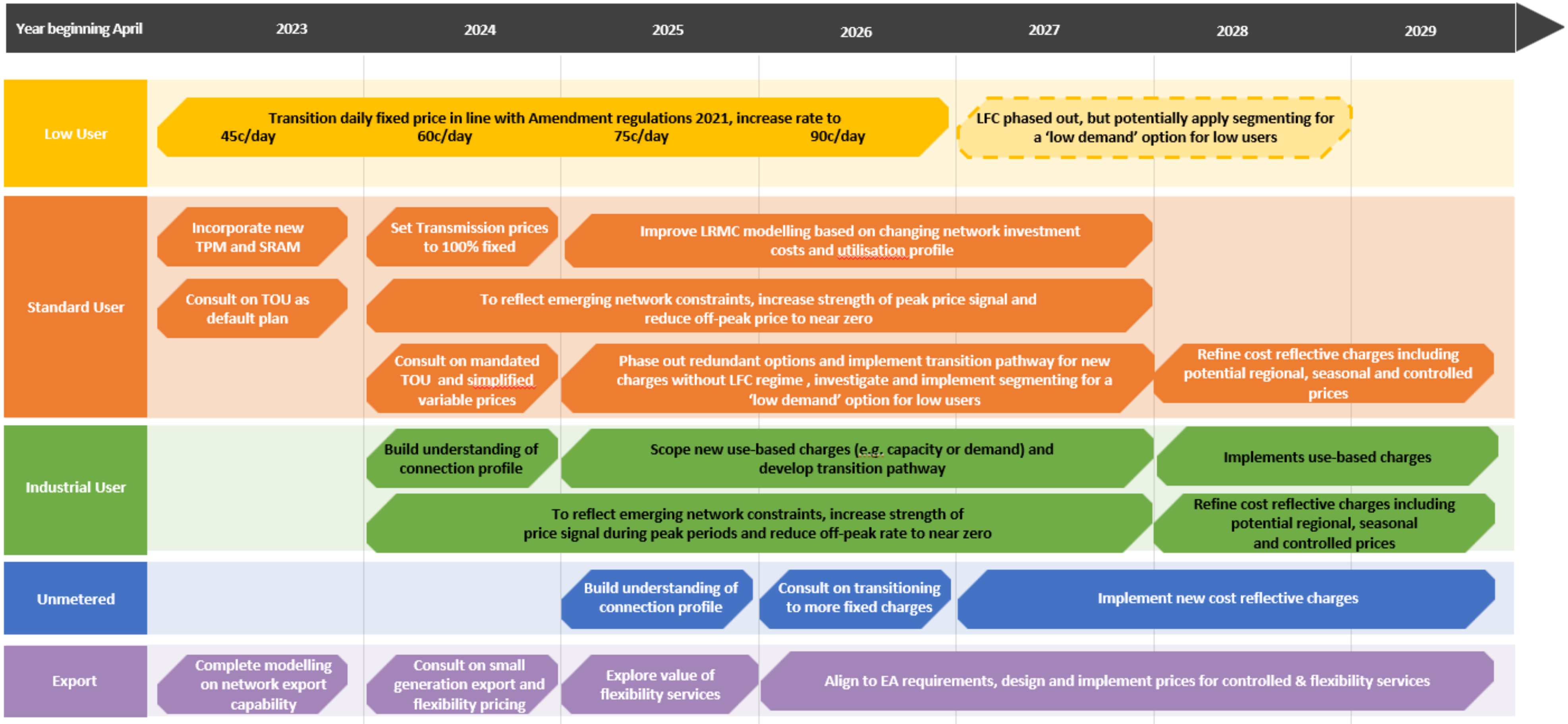
A quick chat with a staff member at Electra is often all that is required to resolve your concern. Call us on 0800 Electra (0800 353 2872) between 8am – 5pm on weekdays and ask to speak with our Customer Experience team. They will take personal responsibility for ensuring your complaint is thoroughly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

We are a member of the Utilities Disputes Scheme, a free and independent service for resolving complaints about utilities providers.

If we do not resolve your complaint to your satisfaction, you can contact Utilities Disputes at 0800 22 33 40 or go to Utilities Disputes.

UTILITIES DISPUTES TAUTOHETOHE WHAIPAINGA

Appendix 1: Pricing Roadmap



Appendix 2: Alignment with Pricing Principles

Pricing principle	*Interpretation*	Alignment
A1) Prices are to signal the economic costs of service provision, including by being subsidy free (equal to or greater than avoidable costs, and less than or equal to standalone costs);	*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.* *• Avoidable costs — are the future cash costs the network avoids if a consumer group were to disconnect from the network.* *• Standalone costs — reflect the costs a consumer would face to supply their energy needs from alternative energy sources.* *Prices above standalone costs cannot be sustained over time as competing energy sources will encourage consumers to bypass the network. While the penetration of distributed generation is increasing, network supply continues to provide greater resilience and has economies of scale associated with shared 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 remaining groups).*	Our methodology allocates costs between consumer groups using cost-reflective allocators. This results in allocations that fall between avoided and standalone costs on average on the basis that the cost allocators used represent the underlying network cost drivers. Consistent with the Authority's Practice Note, avoided costs include short-term future cash costs, such as repairs and maintenance, billing and consumer service costs, and transmission charges. 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. As noted in section 6.3, the nature of our compact network means there is little to no cross-subsidisation between rural and urban connections. However, our decision to apply uniform prices across our two GXPs does however result in consumers connected to our Paraparaumu substation annually paying approximately $46.81 (or +3.3%) per ICP more than their cost to serve. We will continue to monitor the appropriateness of this decision. Similarly, we note in section 6.6, that for April 2026, we have cross subsidisation occurring between consumer groups. Rebalancing our consumer groups has led to a significant reduction in the amount of revenue we can recover from Low Users. While the daily fixed charge is going up, we were minded around the risk of bill shock, so have sought to smooth the transition back to reflective rates. The Authority's Practice Note acknowledges the trade-off distributors must make stating *"benefits [of improved granularity] must be balanced against the costs, complexity, and potential equity concerns of implementation"*[4].

[4] Practice Note, Paragraph 81, at page 15.

Pricing principle	*Interpretation*	Alignment
A2) Prices are to signal the economic costs of service provision, including by: reflecting the impacts of network use on economic costs;	*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** Since 2022, TOU pricing has been available to signal the economic costs of future capacity investments. Disaggregating peak, and off-peak consumption helps Electra to better reflect the economic costs associated with future capacity investment. **Connection capacity** Differences in connection capacity costs are reflected in the low, standard, and commercial and industrial pricing categories. Low and standard consumers are generally connected to LV networks whereas commercial and industrial are connected to high voltage assets. **Streetlights** Separate streetlight charges seek to recover the cost of streetlight assets and maintenance directly. **Load control** We discount our prices to reflect the benefit that controllable load (such as hot water cylinders) provides by reduced network congestion. **Generation** The costs of providing export services are recognised through a generation export charge. Higher peak charges also reflect the benefit of providing network capacity for export consumers and we have brought in the peak rebate option for generation that reduces peak consumption across the network. **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

Pricing principle	*Interpretation*	Alignment
A3) Prices are to signal the economic costs of service provision, including by: reflecting differences in network service provided to (or by) consumers; and	*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.*	In providing network access as a service, our consumers are distinguished by groups including: • Connection capacity sizes are reflected in our Low, Standard, and Commercial and Industrial User Consumer Groups and through capital contributions; • Alternative variable rates to support different metering and consumption profiles are offered through our TOU or general structures; • Export prices are offered for distributed energy resources (DER); • Unmetered loads and streetlights have separate prices reflecting the varying circumstances of these connections and the lack of metering information; and • Non-standard asset specifications and load sizes are catered for through industrial and individual pricing.
A4) Prices are to signal the economic costs of service provision, including by encouraging efficient network alternatives	*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 average charges are estimated to be less than standalone costs for all consumer groups, there are no incentives for consumers to invest in inefficient off-grid energy solutions.* *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, 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. Without storage, solar generation is not typically available to reduce demand at the network peak when our cost to serve is highest (e.g. winter evenings). While TOU pricing structures can signal efficient investments in network alternatives, 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 residential consumers, in line with the phaseout of the LFC Regulations, will also ensure every consumer pays a reflective contribution to fixed network costs, regardless of their level of consumption. This also recognises consumers with solar still contribute to the cost of serving peak demand.
B) Where prices that signal economic costs would under-recover target revenues, the shortfall should be made up by prices that least distort network use	*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 Principles A1-4.* *Economic cost pricing may under-recover total target revenue, especially where economic costs are low, which is currently the case for our prices. Residual cost*	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. Low fixed charge regulations continue to limit 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

Pricing principle	*Interpretation*	Alignment
	should be recovered through non-distortionary pricing mechanisms following Principle B.	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
C) Prices should be responsive to the requirements and circumstances of end users by allowing negotiation to: **i. reflect the economic value of services; and** **ii. enable price/quality trade-offs**	*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.*	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 non-standard terms that better reflect the economic value of the service. Consumers can make price and quality trade-offs in the following ways through our pricing: • TOU 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; and • Export rebates incentivise consumers to store any excess generation to discharge to the wider network during the most constrained periods.
D) Development of prices should be transparent and have regard to transaction costs, consumer impacts, and uptake incentives.	*We interpret this principle as following good pricing practices when developing our prices.* *As our prices evolve 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*	Our pricing is simple and limited to most consumer's fixed daily and variable consumption prices. Our Pricing Methodology and annual price changes are published on our website and 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 3: Alignment with Information Disclosure Requirements

The table in this section provides references for how this pricing methodology complies with 2.4.1 to 2.4.5 of the Electricity Information Disclosure Requirements

Requirement	Reference
2.4.1 Every EDB must publicly disclose, before the start of each disclosure year, a pricing methodology which-	
(1) Describes the methodology, in accordance with clause 2.4.3, used to calculate the prices payable or to be payable;	Section 6
(2) Describes any changes in prices and target revenues;	Sections 6.2 and 6.7
(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);	Section 6.6.3
(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.	Sections 5.1 and 5.6
2.4.2 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 or the different pricing methodology take effect	Will be completed
2.4.3 Every disclosure under clause 2.4.1 above must-	
(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 6.6.2
(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 3, Sections 6.5 and 6.6
(3) State the target revenue expected to be collected for the disclosure year to which the pricing methodology applies;	Sections 6.5 and 6.6
(4) Where applicable, identify the key components of target revenue required to cover the costs and return on investment associated with the EDB's provision of electricity lines services. Disclosure must include the numerical value of each of the components;	Section 6.2 and 6.5
(5) State the consumer groups for whom prices have been set, and describe- (a) the rationale for grouping consumers in this way; (b) the method and the criteria used by the EDB to allocate consumers to each of the consumer groups;	Section 5.3.1 and 6.4

(6) If prices have changed from prices disclosed for the immediately preceding disclosure year, explain the reasons for changes, and quantify the difference in respect of each of those reasons;	Section 6.7
(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 6.5
(8) State the proportion of target revenue (if applicable) that is collected through each price component as publicly disclosed under clause 2.4.18.	Section 6.6
2.4.4 Every disclosure under clause 2.4.1 must, if the EDB has a pricing strategy	
(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; (2) Explain how and why prices for each consumer group are expected to change as a result of the pricing strategy; (3) If the pricing strategy has changed from the preceding disclosure year, identify the changes and explain the reasons for the changes.	Appendix 1 Section 5
2.4.5 Every disclosure under clause 2.4.1 must-	
(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 revenue expected to be collected from consumers subject to non-standard contracts; (b) how the EDB determines whether to use a non-standard contract, including any criteria used; (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;	NA – Electra does not currently have any consumers on non-standard contracts
(3) Describe the EDB's 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.	Section 6.6.3

Appendix 4: Certification of year-beginning disclosures

(Distribution pricing methodology for the year commencing 1 April 2026)

Clause 2.9.1 of section 2.9

We, Murray Ian Bain and Lucy Elizabeth Elwood, 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.

Murray Ian Bain, Chair

27 February 2026

Lucy Elizabeth Elwood, Director

27 February 2026