Electra

ELECTRICITY DISTRIBUTION BUSINESS

PRICING METHODOLOGY

// Effective from 1 April 2022

Contents

1. Overview

This document describes Electra Limited's approach to setting electricity distribution prices that will apply from 1 April 2022. The revenue we earn from these charges enables us to build, operate and maintain an electricity network to serve customers in the Horowhenua and Kāpiti Coast region safely and reliably.

Electricity distribution prices are likely to evolve over the next five to ten years

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

It is important that prices reflect the benefits and impacts of EV and DER connected in customers' premises, together with how they interact with the network and new operational technologies. In the face of these changes, we anticipate there will be an adjustment to 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.

Electra expects to receive a positive benefit from the completion of two major roading projects inside the region – Peka Peka to Ōtaki and Transmission Gully. These roading projects are forecast to greatly improve travel times in and out of Wellington and surrounding areas, with a prediction this could encourage people to relocate out of 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 additional industry relocating here. This will mark a significant change to Electra's existing majority of low-use domestic customers.

Sustainability

Electra is committed to support the Governments reduction in emissions to meet obligations under the Paris Climate Agreement. The company 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 seen as an asset that will prove to be critical in supporting activities such as the electrification of transport and the removal of carbon-based process heat.

Electra has a volunteer sustainability action group, made up of employees from all parts of the organisation, who provide guidance for sustainability activities. As a corporate entity, Electra continues to participate in local and national working groups (Climate Change Commission, NZ Battery Project and EV Connect) that also support opportunities to decarbonise.

Electra's pricing is created with the aim to support New Zealand's goal of being 'Carbon Neutral'. This includes providing pricing plans for export charging and EV tariffs.
Time of Use (ToU) pricing encourages customers to shift load to times where there is greater capacity and therefore avoids unnecessary construction of the distribution network. This focus is also reflected in the annual Asset Management Plan (AMP) that is supporting disruptive technologies such as DER and greater numbers of EVs.

COVID-19

This has been another challenging year with the global effects of Covid-19 impacting staff, customers, and business operation. Electra responded quickly by adapting work practices to safely deliver the essential services and AMP programme. It is anticipated that customer demands will further evolve over the coming years with an increase in home study/working and subsequent adjustment to load profiles across the network.

Impacts on Pricing Strategy

Electra will continue to evolve its pricing as technology and customers behaviours change. Accordingly, a pricing strategy has been developed to guide the development of Electra's electricity distribution prices over the coming years. In summary, the pricing strategy is:

- Electra will progressively introduce service-oriented and cost-reflective price changes to fairly recover the full cost of the network from all customers that use the network (e.g. Electra may refine ToU pricing to improve the alignment of economic price signals).
- The pricing strategy includes key actions (presented in Section 4) and Electra-specific pricing principles (presented in Appendix One) to guide the implementation of the strategy.
- The pricing strategy has a near-term focus on achieving greater cost-reflective, service-oriented pricing, which Electra believes will provide the foundation to manage the impact of the growth in alternative energy sources and seeks to ensure correct allocation of costs across customer groups.

The changes to Electra's prices from 1 April 2022 continue this evolution

Prices that apply from 1 April 2022 include a number of changes that are consistent with the pricing strategy. Key changes to prices for this coming year are set out in Table 1 below.

Change	Impact on Customers
Reduced ToU differentials between peak, shoulder and off-peak prices.	No major impact
First incremental change to low user (LU) fixed charges in line with legislated phase out of low use fixed charge regulations	Potential for energy hardship

Table 1: Changes to prices to apply from 1 April 2022

Electra's Pricing Methodology complies with the regulatory requirements

The Pricing Methodology has been reviewed against the relevant regulatory requirements, and having considered the nature of the network and the practical evolution of Electra's prices to manage disruptive change for customers, it is considered that the approach complies with:

- The Electricity Authority's Pricing Principles
- The Electricity (Low Fixed Charges Price Options for Domestic Customers
- Regulations 2004 (LFC Regulations) including the recent amendments phasing out the LFC regulations by 1 April 2026.
- The Electricity Industry Participation Code, Part 6 - pricing of Distributed Generation
- The Electricity Industry Participation Code, Part 12A - Default distributor agreement / distributor use-of-system agreements and distributor prices

Prices that apply from 1 April 2022

Table 2 sets out the electricity prices that will apply from 1 April 2022 with a comparison of changes from 2021 prices. For further information, please see our published pricing schedule on Electra's website.

Description	Tariff Description	Unit	Price Category	Price Code	Price 2022	Price 2021	% Change
Residential / SME Non ToU Standard (Medium) User	Fixed	$/day	AF	AF	1.08	0.9	20%
	Uncontrolled	$/kWh	AF	AA	0.091	0.0894	2%
	All Inclusive (closed)	$/kWh	AF	CA	0.091	-	-
	Night of Day/Night	$/kWh	AF	DNA	0.034	-	-
	Day of Day/Night	$/kWh	AF	DDA	0.11	-	-
	Controlled 20	$/kWh	AF	MAA	0.037	0.0302	23%
	Night only	$/kWh	AF	NOA	0.033	-	-
	Night Boost	$/kWh	AF	BA	0.034	-	-
Residential / SME Non ToU Low User	Fixed	$/day	F	F	0.3	0.15	100%
	Uncontrolled	$/kWh	F	A	0.126	0.1236	2%
	All Inclusive (closed)	$/kWh	F	C	0.126	0.1118	13%
	Night of Day/Night	$/kWh	F	DN	0.069	0.0372	85%
	Day of Day/Night	$/kWh	F	DD	0.145	0.1516	-4%
	Controlled 20	$/kWh	F	M	0.072	0.0644	12%
	Night only	$/kWh	F	N	0.068	0.0248	174%
	Night Boost	$/kWh	F	B	0.069	0.0372	85%
Residential / SME ToU Standard (Medium) User	Fixed	$/day	XTF	XTF	1.08	0.9	20%
	Off-Peak	$/kWh	XTF	XTN	0.033	0.0286	15%
	Peak	$/kWh	XTF	XTP	0.092	0.0857	7%
	Shoulder	$/kWh	XTF	XTO	0.065	0.0573	13%
	Controlled	$/kWh	XTF	XTM	0.037	0.023	61%
Residential / SME ToU Low User	Fixed	$/day	TF	TF	0.3	0.15	100%
	Off-Peak	$/kWh	TF	TN	0.068	0.0448	52%
	Peak	$/kWh	TF	TP	0.127	0.1347	-6%
	Shoulder	$/kWh	TF	TO	0.1	0.0898	11%
	Contolled	$/kWh	TF	M	0.072	0.0644	12%

Description	Tariff Description	Unit	Price Category	Price Code	Price 2022	Price 2021	% Change
Residential / SME EV TOU Low User	Fixed	$/day	TEVF	TEVF	0.3	0.15	100%
	Off-Peak	$/kWh	TEVF	TEVN	0.052	0.0285	82%
	Peak	$/kWh	TEVF	TEVP	0.127	0.1347	-6%
	Shoulder	$/kWh	TEVF	TEVO	0.1	0.0898	11%
	Controlled	$/kWh	TEVF	TEVM	0.072	0.0644	12%
Industrial	Fixed	$/day	S	S	2.34	1.8012	30%
	Off-Peak	$/kWh	S	SN	0.026	0.0245	6%
	Peak	$/kWh	S	SP	0.074	0.0737	0%
	Shoulder	$/kWh	S	SO	0.051	0.0492	4%
	Capacity Charge	$/kVA/Day	S	SCAP	0	-	-
Apply to all price categories	Export	$/kWh	All	EX	0	-	-
	Unmetered Energy	$/kWh	All	U	0.13	-	-
	Maintenance	$/item/day	All	CM	0.23	-	-
	Lighting	$/fitting/day	All	LGT	0.23	0.22	5%

Table 2: Electra's electricity distribution prices to apply from 1 April 2022

2. Introduction

Across the network, Electra delivers around 416 Gigawatt hours (GWh) of electricity each year from the national grid to approximately 47,000 customers. The energy we deliver is sold to customers via retailers approved to operate on Electra's network.

Electra is owned by customers in Horowhenua Kāpiti through the Electra Trust, which appoints Directors and holds all the shares on behalf of the customers connected to the network.

We supply a geographic area of around 1,700 square kilometres via our distribution network concentrated along the coast connecting urban and rural communities, businesses, and homes from Paekākāriki to Foxton and Tokomaru.

We receive electricity at 33kV from the national grid via two Transpower Grid Exit Points (GXPs). Our northern area (Horowhenua) connects to the Mangahao GXP, the southern area (Kāpiti) connects to Paraparaumu GXP. While there is no continuous connection between these GXPs, Electra's network accommodates a choice of points for the north-south split and is currently treated as one network for pricing purposes.

Our 33kV sub-transmission network supplies a series of 33/11kV zone substations located at population centres across the region. From these zone substations, 11kV distribution feeders reach out into the neighbouring communities where electricity is reduced to 400V through distribution transformers and reticulated throughout neighbourhoods and to rural customers. Almost all customers are connected to this low voltage network though a very small number of large customers are supplied at 11kV.

Overlaying the electricity network, Electra's control systems monitor and manage the integrity of the network, assisting our operations and field staff to build, maintain and, when necessary, conduct emergency work.


Foxton Beach
Foxton
Tokomaru
Shannon
Mangahao
Waitārere Beach
Hokio Beach
Kuku Beach
Levin
Ohau Beach
Waikawa Beach
Manakau
Ōtaki Beach
Ōtaki
Te Horo Beach
Te Horo
Peka Peka
Kāpiti Island
Waikanae Beach
Waikanae
Paraparaumu Beach
Otaihanga
Reikorangi
Paraparaumu
Raumati
Paekākāriki
Substations
Hydro Stations
Planned Substations
Grid Exits
Electra Office/Depot

2.1 Material Projects

Electra has a number of significant projects identified as outlined in our 2021 AMP and in the 2022 AMP update.

PROGRAMME	MAIN DRIVER	PROPOSED TIMING
NETWORK PROJECTS		
Automation of 11kV Ground-mounted switchgear	Quality	FY2023-FY2032
Foxton-Levin West 33kV Bee to Butterfly upgrade	Growth	FY2028-FY2030
Foxton-Shannon Road 11kV upgrade to Bee	Renewal	FY2028-FY2031
Levin East Substation Power Transformer replacement	Renewal	FY2024-FY2025, FY2028-FY2029
Mangahao to Levin East 33kV double-circuit upgrade	Renewal	FY2025-FY2028
New feeder to offload Ōtaki 11kV feeder L351	Growth	FY2031-FY2032
New substation at Waikawa Beach Road, Manakau	Growth	FY2030-FY2031
New substation for Foxton & Shannon load growth and new GXP	Growth	FY2026-FY2027
Northern Network Protection upgrade	Quality	FY2023-FY2032
Raumati Substation Switchgear upgrade	Renewal	FY2025-FY2026
Seismic Strengthening of zone substation buildings	Legislative	FY2023-FY2028
NETWORK PROJECTS		
ISO 550000 - Mahi Tahi Strategic Process Improvement		
Huringa Pūngao Electricity Transformation Roadmap		

Project Mahi Tahi
One of these significant projects is the implementation of an Enterprise Asset Management (EAM) system. The project commenced in 2020 and is expected to go live late in the 2022 calendar year.

Electra has launched the Mahi Tahi programme, to “co-operate, teamwork, collaborate” – bringing together all business areas with the vision “to connect and empower people to one Electra enabled by industry leading technology”, transforming the business by improving operational efficiency and excellence.

Mahi Tahi will deliver a world class technology solution to our business. By sharing more accurate and timely information across our business (‘one source of truth’) and streamlining our processes and tasks, we can focus on providing better experiences for our customers. Mahi Tahi will ultimately make our work more cost-effective and enjoyable by removing bottlenecks and eliminating manual rework and work arounds, allowing Electra to focus on the meaningful services that make a difference to the customers we serve.

Huringa Pūngao
The Energy Transformation Roadmap or Huringa Pūngao initiative launched in June 2021 will ensure that Electra has a pathway to build the necessary capability and capacity to support New Zealand’s decarbonisation efforts.

This project is discussed in further detail later in the document.

2.2 Forecast Expenditure
Projected capital expenditure drivers over the next 10 years are expected to be 61% for renewal and replacement work, 20% for reliability or supply quality, 11% for system growth and 8% for legislative, safety and environmental requirements.

Capital costs are expected to average $13.9m per year over the next 10 years, while operational costs are expected to average $5.2m per year over the same period.

3. Regulatory Context

Commerce Act

As a customer owned distribution business, Electra is incentivised to deliver an efficient and reliable service to its customers. This was formally recognised in 2008 when Electra was exempted from price (now revenue) and quality regulations applying to electricity distribution networks under Part 4 of the Commerce Act 1986, as administered by the Commerce Commission.

While exempt from regulated revenue and quality control, we are subject to regulatory oversight in the form of Information Disclosure regulation. In addition to informing our customers of how we set our prices, this document also supports the requirements of the Commerce Commission's Information Disclosure Determination.

Electricity Authority

We have developed our prices with reference to the Electricity Authority's Pricing Principles (Pricing Principles) and both its August 2019 Practice Note and the refreshed Practice Note published in September 2021. The purpose of the Pricing Principles is to ensure prices are based on a well-defined, clearly explained, and economically rational methodology. These principles provide guidance on economic concepts and market considerations, which are applicable for setting efficient network prices. The Disclosure Determination requires each Electricity Distribution Business to either demonstrate consistency with the Pricing Principles or explain the reasons for any inconsistency.

Appendix One sets out the Pricing Principles and comments on the extent to which our Pricing Methodology is consistent with them.

Low Fixed Charge Regulations

We are subject to the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 (LFC Regulations). The Electricity Authority monitor and enforce the regulations. These regulations require us to offer residential customers a price option at their primary place of residence with a fixed price of no more than 30c per day (excluding GST) and where the sum of the annual fixed and volume charges on that price option equals any other permanent place of residence price option for customers using 8,000 kWh per annum.

This fixed rate has increased from 15c in prior years, following the Government's announcement in September 2021 to phase out the regulations over the next five years.

Electricity Code

We have developed our policies and procedures for installation and connection of distributed generation in accordance with the requirements of Part 6 (Connection of Distributed Generation) of the Electricity Industry Participation Code 2010 (the Code).

4. Pricing Strategy

The EA promotes the provision of cost-reflective distribution price options. Electra supports this initiative, and together with the Electricity Networks Association (ENA), has been liaising with retailers to develop common approaches to make cost-reflective distribution pricing available and visible to end customers within the overall retail price options.

Electra's pricing strategy is to progressively introduce and refine service-oriented and cost-reflective pricing to recover the economic costs of the network and to be responsive to the evolving market and the changing ways that customers are using the network.

The near-term focus is to establish new pricing structures to manage the uptake of EVs and DER to ensure efficient cost signals to key customer groups going forward. The adoption of ToU pricing is a key step in this strategy. Going forward, this will involve an iterative process of fine tuning pricing signals and building 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.

As a network that is dominated by low-user customers, the most significant aspect of Electra's pricing strategy in the next five years will be the transition away from LFC Regulations. With no significant capacity constraints on the network, it has been incongruous with the Pricing Principles that so little of Electra's revenue is recovered from fixed charges. To align with the Pricing Principles, Electra plan to increase the low user (LU) fixed charge consistent with the Government's phase out plan. This will progressively allow for a higher proportion of revenue to be recovered from fixed charges, to lessen the distortion currently caused by the LFC Regulations. Around three-quarters of Electra's revenue is from low-users. Currently (2021/22 pricing year) variable charges contribute 89.5% to revenue, in the first year (2022/23) of LFC removal we expect this to drop to 84.9%. In the absence of LFC Regulations it is estimated that 62.3% of target revenue would come from variable charges.

Huringa Pūngao

In June 2021, Electra started Huringa Pūngao, its energy transformation roadmap to 2040. Electra has created an Energy Transformation Working Group which is tasked with the development and implementation of the roadmap. The roadmap considers the effects on Electra's assets from decarbonisation actions to mitigate climate change. The intent is to follow a low-cost, low-risk pathway, substituting building more infrastructure with acquisition of flexibility services to mitigate demand growth from overloading the network. The forecast impact on customer distribution charges under this pathway is significantly lower than the alternative, even including the expected costs of flexibility services.

The use of DER is continuing to increase, albeit from a very low base. Approximately 940 generation connections exist within Electra's network. This represents 2% of all customers and an installed capacity of 3.9 MW (excluding the Mangahao hydro station). Consistent with Transpower's Whakamana i Te Mauri Hiko "Accelerated Electrification" scenario, it is forecast that DER penetration across Electra's footprint will reach 20% by 2042. This is on an increased ICP count of 61,800 (from around 46,000). Over the same period, EV penetration is expected to reach 75%.

Technological innovation and the adoption of new products for networks and customers will improve reliability, customer service and convenience. Independent analysis has estimated that the maximum value of flexibility services (either controllable DER or the ability to shift demand load) could be around $160 per ICP. In the near term, a core part of our roadmap is to gather more data on the LV network, build data insight tools and increase Electra's engineering capability, particularly related to DER management.

Pricing will also be a focus in our roadmap. A key objective will be to refine price signals to better reflect the economic costs of connecting new load, DER and EVs to the network. We will also need to plan for a future where we may no longer have access to demand control. If access to demand control remains, it is anticipated that Electra will be able to keep long-term price increases beneath the Consumer Price Index (CPI), even with the forecast increases in the electrification of transport and heat. Without demand control, the expected price increases will remain at around CPI.

In the medium term the transformation roadmap is about making 'low-regret' investments which build capability while keeping options open. It is expected that in three years Electra will be well on its way to demonstrating resilience and an active participant in facilitating the required changes in the energy landscape. The additional expenditure requirements to meet this capability building plan over these next three years is not material and would add a fraction of a percent to prices over and above what would otherwise be the case.

The main aspects of this capability-building are summarised below, and will allow us to facilitate the accurate assessment of the cost to serve different customer groups:

- New roles for a 'Data Analyst' and a 'Network Planner'.
- Further modelling on network constraints and financial impacts
- Progressing trials on LV monitoring
- Monitoring consumer uptake of new technology and market evolution

This in turn will facilitate the accurate assessment of the costs to serve customer groups as the network and the customer base evolve.

The path to cost-reflective pricing

The Electricity Authority's distribution pricing principles and recent Practice Note encourage electricity networks to adopt cost reflective pricing. Key principles are that:

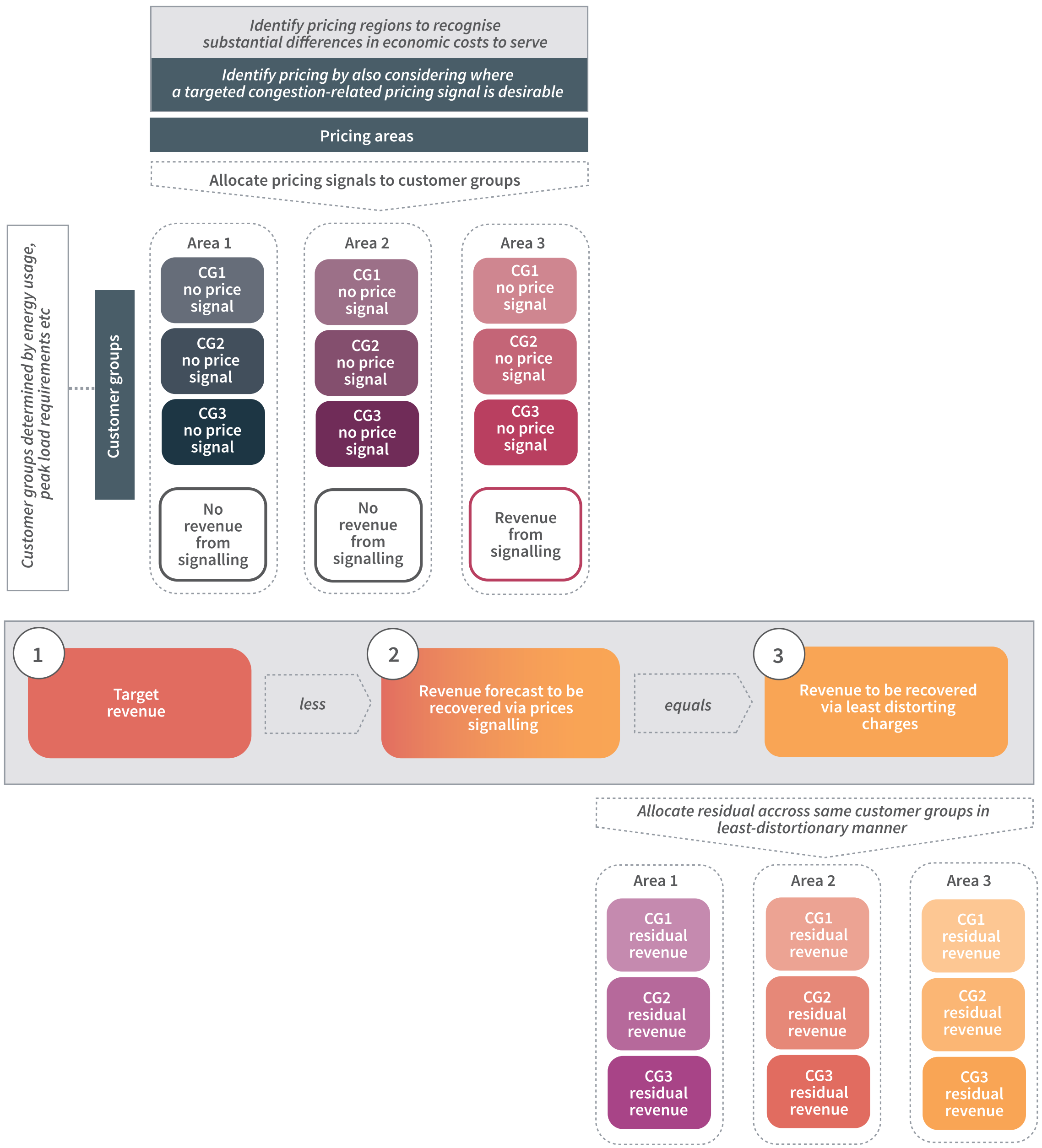
- Prices should signal the economic costs of providing network services.
- Any residual revenue required to recover an EDBs target revenue should be recovered by prices that least distort network usage.

Electra plan to undertake work (as below) in the coming years to better align its methodology with the Pricing Principles. Further information on how our pricing methodology is consistent with the Pricing Principles is provided in Appendix One.

Electra's primary service is providing customers with differing levels of capacity in the network. This typically reflects the maximum amount of energy that can be transmitted through the network at a point in time to serve a customer. Cost reflective pricing should target the periods when this network capacity is congested in order to signal to users the future economic costs of upgrading capacity.

ToU is one pricing tool being applied across the sector to align customer prices to future capacity costs. This provides for higher prices during peak periods of congestion, and lower prices during off-peak or shoulder periods.

While Electra's network is not significantly constrained at present, population growth may be significant once transport links to Wellington open, reducing travel times to the Kāpiti and Horowhenua region. Electra has recently introduced a ToU pricing option that will help to signal peak usage periods before a physical constraint on the network arises.



This sends a signal that allows customers to become aware of the periods when the network is most constrained. It also gives Electra tools to respond quickly to changes in network usage and demand. The forecast growth in the Electra network, from both population growth (ICPs) and DER uptake, means that it is prudent to introduce these tools early.

A lack of data and analytical capacity has meant that assessing proportionate costs signalling has had to be by empirical methods to this point. The Cost of Supply model update planned for the 2021/22 pricing year has yet to be completed to an appropriate level. In the coming year Electra will engage advisors to estimate the economic costs of serving different consumer groups, that will include estimates of avoidable costs (AC), residual costs, and standalone costs (SAC). This information will be used to refine price signals for ToU pricing and consider optimal balances of fixed charges to better align pricing to concepts of economic and residual costs. The Cost of Supply model will also be updated over the next year.

With the phase out of the LFC Regulations, there will be greater freedom to align pricing to economic and residual costs. The need to maintain target revenue and mitigate price shock has meant that this year variable price components have had to rise along with fixed price components and Electra is aware that this is inconsistent with its strategy.

Customer engagement

Central to an effective signal is the ability of the customer to understand and respond to the signal. Given the current demand conditions, the signals Electra has been sending with its ToU and Day/Night differentials have been too strong for the required purpose and have been reduced this year. Nevertheless, implementing this pricing has continued to improve understanding of customer behaviour. Refining this signal will be an ongoing piece of work (as described above).

Customer impact

Electra assesses the impact on customers of each change to price structure and price level, taking account of:

- The scale of changes to line charges for customers or a customer 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 customers. Electra engages with retailers about how any changes might impact on their customer bills.

Across the Electra network, individuals, households and whanau face energy hardship in their homes or kainga. Electra has been striving for several years through education, pricing and supporting agencies (EnergyMate, Levin Budget Services, Warmerhomes) to facilitate moving customers from a position of energy hardship to one of energy wellbeing. This will be a particularly important part of the next five years as the LFC Regulations are phased out. The majority of Electra’s customer base will be affected by these changes. Electra will continue to work to rebalance the variable proportion of target revenue to mitigate these increases on low-users. However, in the interim it will continue to focus on actively encouraging customers to use services like Powerswitch.org.nz to help reduce their overall electricity bill.

Progress on the pricing roadmap

Electra’s recent focus has been on understanding the future demand outlook for its service area, undertaken as part of Huringa Pūngao, and how it prepares for this. This work will inform a refreshed view on the pricing roadmap for the next five years. There is renewed commitment for the coming year to implement a pricing methodology in keeping with Electra’s pricing strategy and with improved alignment to the Pricing Principles. Refinements will also be investigated to ToU pricing to better signal avoidable and residual costs.

Electra Pricing Roadmap

2022/23	2023/24	2024/25	2025/26	2026/27
• Review impact of first incremental increase of LFC • Review pricing in response to TPM • Consult on ToU as default plan • Engage consultants to accurately estimate economic and residual costs • Redefine customer groups and update cost of supply model • New roles established	• Implement updated pricing methodology • Review impact of second incremental increase of LFC • Complete modelling on export capabilities on network • Consult on charging for various Registry ICP 01 Status	• Review impact of third incremental increase of LFC • Review and refine updated pricing • Consult on small generation export charging • Consult on flexibility pricing • Implement LV Monitoring	• Review impact of fourth incremental increase of LFC • Review and refine updated pricing • Review estimates of economic and residual costs • Update forecast model based on LV monitoring and other updated information • Value flexibility services	• Review impact of fifth incremental increase of LFC • Update pricing methodology to include flexibility services

5. Pricing Methodology

Electra have maintained the same approach to setting prices in 2022/23 as last year. Key steps in the price setting process are as follows:

1. Determine the amount of target revenue to be recovered via prices over the pricing period (1 April 2022 – 31 March 2023) through consideration of budgets, asset management plans and customer impacts (Section 6);
2. Review and/or confirm customer groupings (Section 7) and pricing structures (Section 10 and 11) with consideration of economic pricing principles (Appendix One) and other network and customer matters;
3. Allocate the target revenue requirement to load groups and price categories (Section 10 and 11) and set unit charges based on forecast billing volumes.

Further information on these key steps is provided in the sections below (as identified above).

The price signals have been adjusted from last year to be more consistent across price categories and to be more appropriate to the level of network constraint, we expect this to be an ongoing exercise as rebundling of price options means that not every customer is able see and responded to our price signals. We see this as a limitation on how customer behaviours can mature to respond to price signals in a timely manner.

6. Target Revenue

We determine our target revenue requirement from our Asset Management Plan and our budgeting process. The target revenue is the amount of money we require to safely and reliably provide an electricity network service to all electricity customers in the Horowhenua and Kāpiti Coast regions. The target revenue provides funding for our operating costs, a return to our customer owners, and the majority of capital required for reinvestment into the network.

Target Revenue for the year ending 31 March 2023 to be recovered through prices is $45.1m which covers the following components.

The target revenue is $2m up on 2022 forecast and is shown inclusive of the discount to be paid during the pricing year.

Target revenue has increased in 2023 due to increasing operating costs, including but not limited to network maintenance, salaries and wages, and ICT costs.
We are seeing a trending increase in consumption across our network, this has also contributed to the increase in revenue to be recovered through prices.

Type	Component	2022 forecast $m	2023 budget $m
Distribution	Operating Expenditure	14.5	16.3
	Sales Discount	5.1	5.1
	Depreciation	9.3	10.6
	Regulatory Tax Allowance	1.7	1.6
	Revaluations	(3.1)	(3.2)
	Other Regulated Income	(1.8)	(1.7)
	Return on Investment	7.9	6.5
Pass Through	Transmission	9.5	9.9
	Rates & Levies	.03	.04
Total		43.1	45.1

2.1 Price Changes

As a result of an increase in target revenue, overall prices will increase for customers for 2023.

Distribution charges make up around 77% of total network charges for customers. These have increased for 2023 by an average of 7.5%. This increase reflects the annual change to our target revenue, which we target to be in line with our peer EDBs who are regulated by the Commerce Commission. We note that most regulated companies are generally accumulating revenue shortfalls at present which will lead to a need for a large price 'catch-up' at the end of the current regulatory period.

Transmission charges and other pass-through costs make up the remainder of the network charges to customers and have increased by around 5.5%.

Overall, Electra expects the average residential customers distribution bill to increase by around 11.5%.

Additionally, we have commenced year one of the change linked to the removal of the Low Fixed Charge regulations. We expect to incrementally increase our low user fixed prices by $0.15 per year (15 cents) over the next five years.

2.2 Other changes to our pricing

1. Additional price options

We have added Day/Night, Boost and Night Boost to our medium user price options. This was as a result of retailer consultation in the prior year.

2. Rebalance

As part of our price model review, we have identified the need to correct the differential in our time of use options to better align with best practice discount/premium concepts. The result of this is an increase to the Night and Off-Peak prices and a decrease to the Peak.

Controlled 20, Night and Night Boost prices have been rebalanced to correct price disparity between the same time of day.

For Medium User and Standard & Industrial we have proceeded with ensuring cost recovery via the fixed price components.

3. New Post Discount Prices

From 1 April 2022 Electra will publish post discount prices. This is to ensure we meet our obligations outlined in the Default Distributor Agreement under Schedule 10.
The post discount prices will be used by Electra to calculate the discount owed to customers which is administered in February each year.

2.3 Network Growth

Over the last five years we have seen a 4% growth in consumption at GXP level. For 2023 this has translated to a target of 422m units billed compared with 416m budget in 2022.
The increase in GXP consumption combined with a favourable reduction in non-technical losses for 2022 has contributed to the increase in target revenue for 2023.

7. Customer Groups

The basis for the customer groupings we have adopted in our 2022/23 pricing methodology is unchanged from last year.

We established the three primary customer groups as part of our 2013 pricing review. We have reviewed these customer groups during our most recent pricing strategy review and consider that they remain unchanged in the current phase of our pricing road map.

Street lighting and community lighting is a separate customer group. This recognises that these connections use dedicated assets (i.e. streetlight circuits) and have unique demand profiles (i.e. at night).

8. Customer Considerations

Customer ownership

Electra is owned by its customers through the Electra Trust. As a trust-owned company we endeavour to ensure the customer is at the heart of all decision making.

Customer feedback

Each year we undertake a survey of our customers in order to better understand their views on prices, quality of supply, and consumption patterns. We surveyed 300 customers (both residential and commercial). As we complete this version of the Pricing Methodology, preliminary indications from this year's survey are outlined, with customer feedback included:

% of respondents that	Customers type	2017	2018	2019	2020	2021
Provides a reliable electricity supply	Overall	93%	90%	93%	96%	94%
	Domestic	95%	91%	93%	97%	94%
	Commercial	90%	88%	94%	96%	92%
Fixes fault quickly	Overall	75%	72%	66%	96%	98%
	Domestic	78%	75%	68%	NS	NS
	Commercial	69%	67%	62%	NS	NS

NS: Not Separated

The survey highlighted a continued increasing requirement from customers to receive up to date information on outages. How long the power outage will be and when it will be back on. The reliance on a reliable electricity supply has grown significantly with customers reporting that they are spending more time working and studying at home. 42% of the respondents are already working from home on a regular basis.

The survey reconfirmed an increasing use of energy efficient products, which is expected to continue to exert downward pressure on consumption.

The survey also highlighted a growing interest from customers in alternative forms of energy with 11% of respondents indicating they had installed solar photovoltaic (“PV”) supply and 33% suggesting they were considering purchasing a system. The installation of PV creates both commercial and operational challenges and opportunities for the network. In addition to PV’s there is significant interest in purchasing an EV, 42% of respondents suggested they were considering an EV instead of an ICE vehicle, with 8% of the respondents having already purchased an EV.

Last year Electra reduced line charges for most customer groups. During the survey customers were asked if they had noticed a reduction in their bill, most responded that they had not noticed a reduction in the overall bill nor being moved to a favourable plan. During Q3/Q4 of 2020/21 Electra ran the Money for Jam campaign, this encouraged customers to seek out the best plan with their retailer and also to check the Powerswitch site. Of those surveyed 20% recall the campaign. Electra will continue with variations on the campaign (Check,Switch,Save) throughout 2022/23 to encourage customers to realise savings that are available.

The price signals have been adjusted from last year to be more consistent across price categories and to be more appropriate to the level of network constraint, we expect this to be an ongoing exercise as rebundling of price options means that not every customer is able see and respond to our price signals. We see this as limitation on how customer behaviours can mature to respond to price single in a timely manner.

9. Cost Drivers

Overview of network attributes that influence cost drivers

We have considered the relevant drivers of costs that we are seeking to recover, to inform our decisions on customer groupings, price structures, and the level of charges.

Our costs are associated with investing in, maintaining, and operating the network together with the costs of taking supply from Transpower's network. The remaining costs are associated with general management and administration. The key cost drivers relevant to setting prices are therefore weighted heavily towards investment in, and operation of, the network.

Key network attributes that influence the quantity of assets and their associated operating costs are:

- The capacity of the network (measured in kVA)
- The length of circuit required to supply customers (measured in kms)
- The number of customer connections (measured in ICPs)
- Customer-specific asset use
- Reliability expectations

Network Attribute	Value
Customer Numbers (no.)	46,000
Total circuit length (km)	2,330
Customer density (ICPs/km)	20.17
Zone substation installed firm capacity (MVA)	352
Maximum energy demand (MW)	111
Energy delivered to ICPs (GWh)	416
Energy density (kWh/ICP)	8,851

Network capacity
Our network is designed and operated to meet forecast 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.

However, as can be seen in the table above, Electra's network maximum demand of 111MW is well below the zone substation installed capacity of 352 MW. This broad measure indicates that the network is not constrained at its key nodes, however Electra has been imposed a terminal constraint at its Mangahao GXP by Transpower, the limit of 38MW means that at times during winter peak periods, Electra needs to invoke load control to ensure we are below the constraint.

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

More specifically, forecast constraints at 11kV distribution and 400V reticulation are addressed as set out in our AMP and are under review as part of our Energy Transformation Working Group.

Circuit length
The length of circuit required to transmit electricity from the GXP to customers is a key driver of network investment costs. Customers who are further from the main supply areas create relatively higher costs for Electra. However, in comparison to other NZ networks, Electra's is relatively compact and ongoing meshing of the distribution network in urban centres and rural areas makes it difficult to distinguish line length for a particular customer or group of customers (due to the difficulty in tracking electrical flows). While customers density decreases towards the edge of the network, most of the network length is shared across our entire customer base.

Customer connections
New connections, and upgrades to connections, drive asset-related and maintenance costs. Electra's Network Extension Policy requires customers to pay for connection-related asset costs upfront. At the time of writing, this policy and the associated contribution model is under review.

Each new connection also incrementally increases costs of network operations and planning, fault restoration, maintenance, and general administration.

Customer-specific asset usage
Where practical, the network costs that directly relate to a particular customer or group of customers are identified and recovered from those parties. This aligns recovery of costs with the beneficiary of those assets. Street lighting and community lighting is a customer group that has specific assets identifiable and allocated to that group.

In 2013 we considered whether customer-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 that there is very little variation in asset utilisation within our customer base (e.g. less than 0.01% of customers directly connect to 11kV feeders). However, this is beginning to change. To reflect this change, in 2021/22 we introduced a zero-rated capacity charge for the S price category that will increase in the future to reflect the costs of dedicated equipment. For those customers that require dedicated equipment, this had 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 used in combination to have more cost reflective pricing and asset allocation.

10. Allocation of Target Revenue to Customer Groups

We use our Cost of Supply model to allocate the costs of owning and operating the distribution network to the consumer groups described in the previous section, to determine how much of the target revenue we intend to recover from each customer group. The allocators reflect how the different customer groups drive the cost components.

Budget item	Choose from list
Transmission Charges	CMD
Rates	ICP's
Commerce Commission Levy	ICP's
Utilities Disputes Levy	ICP's
FENZ Levy	ICP's
EA Levy Variable	kWh
EA Levy Fixed	ICP's
Sales Discount	kWh
All other opex	ICP's

The table below sets out the proportion of target revenue forecast (net of transmission) to be recovered from each price option in the 2022/23 pricing year.

Category	Target Cost Allocation	Estimated Consumption	Customer Count
F-AF	$16,932,872	147,846,966	19,586
S-ToU	$2,695,616	89,743,463	276
TEVF-XTEVF ToU	$10,339	51,553	6
TF-XTF ToU	$25,509,991	184,272,966	26,181
Total	**$145,148,818**	**421,914,948**	**46,049**

The transmission charge component of the target revenue includes the following. Transpower-related charges:

- Interconnection Charges: based on Electra's relative contribution to Regional Coincident Peak Demand (RCPD) in the Lower North Island region of the transmission grid
- Connection Charges: for the provision of connection assets at the two GXPs from which Electra receives supply from the grid
- New Investment Agreement Charges: in relation to new connection assets

Transpower also calculates a losses and constraints excess and returns this to distributors over the pricing year. As these are not known at the time of setting prices, Electra estimates the amount on an annual basis and includes this credit in the transmission revenue requirement.

In relation to the avoided cost of transmission included in the target revenue, Electra is responsible for paying all transmission charges associated with the Mangahao GXP. There is a generating station located at Mangahao and it reduces the demand placed on the transmission network (it reduces the RCPD at the GXP) and therefore reduces the total charges payable to Transpower for transmission services. In recognition for this service, we pay the Mangahao power station a share of the savings (i.e. the avoided cost of transmission). We also retain some of these savings, which is a benefit to the customers on the Electra network.

Transpower have recently reviewed their Transmission Pricing Methodology (TPM) to commence from 1 April 2023.

The new methodology has removed the use of RCPD to calculate the Interconnection Charge. This will be replaced with the following charges:

- **Connection charges,** which recover part of recoverable revenue by reference to the cost of connection investments. Part C specifies how connection charges are calculated; and
- **Benefit-based charges,** which recover part of recoverable revenue by reference to the covered cost of benefit-based investments. Part D specifies how benefit based charges are calculated; and
- **Cap recovery charges,** which are a redistribution of transmission charges that would otherwise be payable by capped customers who are receiving cap reductions; and
- **Prudent discount recovery charges,** which are a redistribution of transmission charges that would otherwise be payable by prudent discount recipients; and
- **Residual charges,** which recover the remainder of recoverable revenue. Part E specifies how residual charges are calculated.

The new charges are designed so that consumers pay for the transmission assets and investments they benefit from. This will send clearer signals to consumers and reduce inefficient grid investment and grid use. The final TPM is yet to be approved by the Electricity Authority.

Transpower's charges have increased for 2022/23. We have seen an increase in costs at Mangahao GXP related to Interconnection Charges. This is largely driven by being unable to reduce our contribution to RCPD events during winter 2021.

Operating Costs

The operating and maintenance costs included in the target revenue are obtained from Electra's Asset Management Plan (AMP) forecasts. The AMP specifies, in some detail, our plans for the maintenance and development of the network and includes the forecast cost for these activities. Operating and maintenance costs have increased in 2023 due to the increase in cost from our suppliers and contractors.

Administration and overheads

Administration and overhead costs are incurred in running the distribution business activities of Electra. These costs are driven by our requirement to manage the non-engineering aspects of the business, which includes customer management, regulatory management and compliance, finance and payroll, information systems, general management, governance, and industry levies. We obtain these costs from our AMP.

Administration and overhead costs have increased due to an increase in employee costs and expenditure required to ensure the resiliency of the ICT network. As more ICT systems become Software as a Service (SaaS) we are also seeing an increase in our baseline ICT costs.

Depreciation and Return on Investment

Depreciation reflects the 'return of capital' from the consumption of economic life of the network assets. This charge is a standard calculation of depreciation and is based on the useful economic life of the assets. This return allows us to replace assets as they near the end of their lives and invest in new assets as the network grows and new technology is available.

The extent of these capital projects is shown in our AMP.

Depreciation for 2023 is higher than 2022 as a result of increases to Electra's asset base. This drives higher depreciation, offset by the recognition of disposals, that result from planned renewal projects.

11. Price Options & Design

Prices for 2023

Post-discount prices for 2023 will also be disclosed. Customers will still receive their fixed discount of $30 and the remaining discount will be calculated based on their variable (kWh consumption).

The discount eligibility rule of being connected to the Electra network at 31 January remains.

Description	Tariff Description	Unit	Price Category	Price Code	Price ($) 2021/22	Price ($) 2022/23	Post Discount Price ($) 2022/23
Residential / SME Non ToU Standard User	Fixed	$/day	AF	AF	0.9000	1.08	0.9978
	Uncontrolled	$/kWh	AF	AA	0.0857	0.091	0.0822
	All Inclusive (closed)	$/kWh	AF	CA	-	0.091	0.0822
	Night of Day/Night	$/kWh	AF	DNA	-	0.034	0.0252
	Day of Day/Night	$/kWh	AF	DDA	-	0.11	0.1012
	Controlled 20	$/kWh	AF	MAA	0.0283	0.037	0.0282
	Night only	$/kWh	AF	NOA	-	0.033	0.0242
	Night Boost	$/kWh	AF	BA	-	0.034	0.0252
Residential / SME Non ToU Low User	Fixed	$/day	F	F	0.1500	0.3	0.2178
	Uncontrolled	$/kWh	F	A	0.1199	0.126	0.1172
	All Inclusive (closed)	$/kWh	F	C	0.1085	0.126	0.1172
	Night of Day/Night	$/kWh	F	DN	0.0361	0.069	0.0602
	Day of Day/Night	$/kWh	F	DD	0.1471	0.145	0.1362
	Controlled 20	$/kWh	F	M	0.0625	0.072	0.0632
	Night only	$/kWh	F	N	0.0241	0.068	0.0592
	Night Boost	$/kWh	F	B	0.0361	0.069	0.0602
Residential / SME ToU Standard User	Fixed	$/day	XTF	XTF	0.9000	1.08	0.9978
	Off-Peak	$/kWh	XTF	XTN	0.0276	0.033	0.0242
	Peak	$/kWh	XTF	XTP	0.0830	0.092	0.0832
	Shoulder	$/kWh	XTF	XTO	0.0555	0.065	0.0562
	Controlled	$/kWh	XTF	XTM	0.0223	0.037	0.0282

Description	Tariff Description	Unit	Price Category	Price Code	Price ($) 2021/22	Price ($) 2022/23	Post Discount Price ($) 2022/23
Residential / SME ToU Low User	Fixed	$/day	TF	TF	0.1500	0.3	0.2178
	Off-Peak	$/kWh	TF	TN	0.0435	0.068	0.0592
	Peak	$/kWh	TF	TP	0.1307	0.127	0.1182
	Shoulder	$/kWh	TF	TO	0.0871	0.1	0.0912
	Contolled	$/kWh	TF	M	0.0625	0.072	0.0632
Residential / SME EV ToU Standard User	Fixed	$/day	XTEVF	XTEVF	0.9000	1.08	0.9978
	Off-Peak	$/kWh	XTEVF	XTEVN	0.0115	0.017	0.0082
	Peak	$/kWh	XTEVF	XTEVP	0.0830	0.092	0.0832
	Shoulder	$/kWh	XTEVF	XTEVO	0.0555	0.065	0.0562
	Controlled	$/kWh	XTEVF	XTEVM	0.0223	0.037	0.0282
Residential / SME EV ToU Low User	Fixed	$/day	TEVF	TEVF	0.1500	0.3	0.2178
	Off-Peak	$/kWh	TEVF	TEVN	0.0277	0.052	0.0432
	Peak	$/kWh	TEVF	TEVP	0.1307	0.127	0.1182
	Shoulder	$/kWh	TEVF	TEVO	0.0871	0.1	0.0912
	Controlled	$/kWh	TEVF	TEVM	0.0625	0.072	0.0632
Industrial	Fixed	$/day	S	S	1.8012	2.34	2.2578
	Off-Peak	$/kWh	S	SN	0.0238	0.026	0.0172
	Peak	$/kWh	S	SP	0.0716	0.074	0.0652
	Shoulder	$/kWh	S	SO	0.0477	0.051	0.0422
	Capacity Charge	$/kVA/Day	S	SCAP	0.0000	0	0
Apply to all price categories	Export	$/kWh	All	EX	0.0000	0	0
	Unmetered Energy	$/kWh	All	U	0.1042	0.13	0.13
	Un Maintenance	$/item/ day	All	CM	0.1500	0.23	0.23

Explanation of Electra's price options

Name	Description	Code	Price Component		Unit of measure
Residential / SME		Low, Standard			
Fixed Price	Daily fixed charge applicable to non-Time of Use customers.	F, AF	n/a		dollar/day
Uncontrolled	A standard price for using electricity at any time of the day.	A, AA	n/a		dollar/kWh
Controlled 20	A price which customers may choose for hot water heating (and for other uses) on the basis that supply is able to be interrupted in return for a lower price. Electra can switch off load for up to 4 hours each day under this price.	M, MAA	n/a		dollar/kWh
All Inclusive	Closed option	C, CA	n/a		dollar/kWh
Night	A night rate between 23:00 and 7:00 reflecting the amount of available capacity on the network during this period. This does not function as a standalone option and must be on a circuit only on during these hours, used in conjunction with another price option for other load.	N. NOA	Night only	2300-0700	dollar/kWh
Night Boost	As for Night with the addition of an afternoon heating boost.	B BA	Night	2300-0700	dollar/kWh
			Day	1300-1600	dollar/kWh
Day/Night	For continuous electricity supply at two time 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	dollar/kWh
		DD, DDA	Day	0700-2100	dollar/kWh
Export	For those that are generating electricity and exporting some or all of this.	EX	n/a		dollar/kWh
Fixed Price TOU	Daily fixed charge applicable to Time of Use customers.	TF, XTF	n/a		dollar/day
Time of Use	A three rate (peak, off-peak and night) time-of-use option available to all customers with the ability to move load or otherwise take advantage of price signals. With an additional option for separately metered controlled load.	TN, XTN	Night	2300-0700	dollar/kWh
		TP, XTP	Peak	0700-1100	dollar/kWh
			Off peak	1700-2100	dollar/kWh
		TO, XTO		1100-1700	dollar/kWh
				2100-2300	dollar/kWh
		M, XTM	n/a		dollar/kWh
Fixed Price EV TOU	Daily fixed charge applicable to Time of Use customers with an electric car registered with Electra.	TEVF, XTEVF	n/a		dollar/day
Time of Use EV	As for Time of Use, with an electric car registered with Electra.	TEVN, XTEVN	Night	2300-0700	dollar/day
		TEVP, XTEVP	Peak	0700-1100	dollar/kWh
			Off peak	1700-2100	dollar/kWh
		TEVO, XTEVO		1100-1700	dollar/kWh
				2100-2300	dollar/kWh
		TEVM, XTEVM	n/a		dollar/kWh

Name	Description	Code	Price Component		Unit of measure
Large Customers					
Fixed Price Industrial	Daily fixed charge applicable to customers on the Industrial pricing option.	S	n/a		dollar/day
Industrial	A three rate (peak, off-peak and night) ToU option which differs from the Time of Use price by higher fixed and lower variable charges. It is targeted at larger commercial customers by rewarding those able to move load away from peak, or otherwise take advantage of price signals.	SN	Night	2300-0700	dollar/kWh
		SP	Peak	0700-1100	dollar/kWh
				1700-2100	dollar/kWh
		SO	Off peak	1100-1700	dollar/kWh
				2100-2300	dollar/kWh
Industrial Capacity	Related to the size of an ICPs connection and related equipment needed for its energy demand. 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	n/a		dollar/kVA/day
Residential / SME		Low, Standard			
Power Factor	Where the power factor is less than 0.95 Electra reserves 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	n/a		dollar/0.01 lagging
Street Lighting and Community Lighting					
Unmetered Energy	Unmetered Energy Charge.	U	Timetable		dollar/kWh
Unmetered Maintenance	This is a new price to recover the costs of maintaining unmetered Items.	CM	Each Item		dollar/Item/day
Lighting	All current under veranda lighting.	LGT	Each Fitting		dollar/Item/day

12. Discussion on Price Option Design

Overall price design elements

Electra's prices are focused on the mass market (small and medium customer group) because the customer base is dominated by small loads. Domestic and small commercial users represent approximately 98% of connections and over 80% of consumption. As a result, Electra has the lowest average use per connection of all New Zealand electricity distribution businesses (approximately 9,244 kWh per customer compared to the industry average of more than 16,000 kWh per customer).

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

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

All price 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, respectively.

Specific prices in the small, medium, and large customer groups incorporate signals which enable customers to achieve lower overall cost of supply by moving their consumption to off-peak periods and to offer interruptible load. This aligns our pricing incentives to the cost of network capacity and capacity utilisation. Specifically, these targets are aimed at reducing Electra's exposure to Transpower's RCPD pricing.

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

Variable charge components

A variable price based on kWh consumption is applied to all price groups. The evolution of our AA and XT price groups to include control continues to offer lower energy charges for residential customers while recovering a greater proportion of our fixed costs through a higher daily charge. Electra will continue to evolve its pricing to recover cost via its fixed components. Together with our LFC price options Electra now offers a broader mix of options that:

- Aligns with existing retail pricing structures
- Aligns with the LFC regulations
- Introduces options that have daily charges more closely reflecting the fixed costs of an EDB which is also aligned with the Electricity Authority's cost reflective pricing initiative

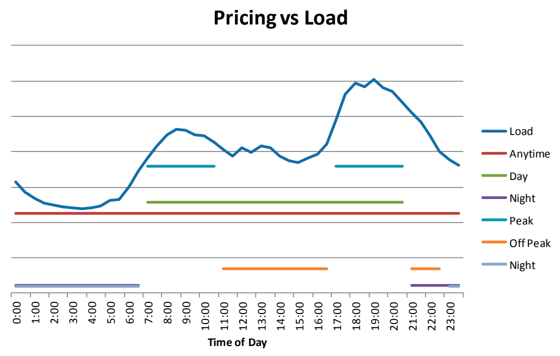
Time of Use charge components

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 shoulders and off-peak periods.

In regard to Electra's network capacity, we are progressively closing the gap between the Peak and Night components of our ToU plans. The results will be a 'flatter' differential to reflect the spare off-peak capacity. Electra intend to review these yearly and change this differential in response to network usage and customer behaviours.

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

The figure below illustrates our time of use price options, usage periods, and how these pricing periods align to our typical daily load profile.

Price	Time-of-Use Periods	
Night	• Off-peak rate from 2300-0700 • Other times charged at the Managed Saver or Combined rates	
Night Boost	• Off-peak rate from 2300-0700 • Boost from 1300-1600 • Other times charged at the Managed Saver or Combined rates	
Night/Day	• Night rate from 2100-0700 • Day rate from 0700-2100	
Time of Use Standard	• Night rate from 2300-0700 • Peak rate from 0700-1100 & 1700-2100 • Off-peak rates from 1100-1700 and 2100-2300	

Controlled load price option

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

Electra will review the amount of total controlled price options we have available over the next 12 – 24 months with a view to simplify.

Unmetered price option

A variable charge has been removed for most of our community lighting. We have added a standard fixed price that recognises increasing replacement costs and the lower consumption of LED lights. This recognises network capacity use as well as the use of dedicated assets such as street lighting circuits and poles.

Uncontrolled price option

Other customers are charged under the Uncontrolled price option (often in combination with controlled load price options). Approximately 50% of customers have an Uncontrolled connection. The Uncontrolled price option recognises that these customers are able to use the network at any time up to the capacity of their connection.

Fixed charge components

A fixed daily charge is applied to all customers. We consider that our fixed charge options appropriately recognise:

- Investments in existing network capacity
- Connection cost drivers
- Our need for revenue stability
- The LFC regulations
- The Electricity Authority's cost reflective pricing initiative

Power factor charges

We reserve the option to apply an additional charge where a commercial customer has a power factor materially 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 ultimate goal of avoiding unnecessary network reinforcement.

Distributed Generation (DG) price option

Electra has a small number of DG sites connected to its network (1% of connections). All but six of these are small sites (less than 10kW) which are connected at 400V. We use standard charging for import meters and do not charge for distributing exported energy. In 2021/22 we introduced an export price, which would potentially enable us to do this. Currently, it is set at zero cents per kWh. This has been introduced to help us monitor the uptake of DG on the network.

We currently do not make direct payments to DG for the avoided cost of transmission or distribution as it is not practical to do so. Avoided costs are recognised by not charging generators for injection into the network. We believe this approach is consistent with the incremental cost pricing principle under Part 6 of the Electricity Industry Participation Code. We do expect that we will need to recover our incremental costs driven by distributed generation in the future.

Mangahao power station near Shannon is notionally embedded for transmission purposes. We are responsible for paying all connection charges associated with the Mangahao GXP, but our customers share in the avoided Transpower charges that result from the generator reducing peak grid demand at this GXP. ACOT is therefore implicitly recognised in this arrangement.

As of November 2021, Electra has approved network connection for a large solar farm and is aware of another two developments looking to be built within the network. We are keeping track of the progress on these projects.

Non-standard pricing

We currently do not have any non-standard pricing arrangements. We will assess any requests for non-standard pricing as required.

Network extensions policy

In addition to distribution prices, customers are required to fully fund the cost of their own 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 customers. Where these assets are vested with Electra, we will pay for the ongoing maintenance and operation of the assets. We may also provide a payment to customers where the required asset upgrade exceeds the customer's requirements.

Distribution prices do not seek to recover connection costs paid for by customers under our network extension policy. Further information on our network extension policy can be found on our website at: **https://electra.co.nz/our-company/disclosures/**

Appendix One:

Consistency with the Electricity Authority's Pricing Principles

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

i. 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 customer group falls within the subsidy-free range established by standalone cost (SAC) and avoidable cost (AC). SAC reflects the costs that a customer would face to supply their energy needs from alternative energy sources. AC is the future cash costs the network avoids if a customer group were to disconnect from the network.

Electra will engage advisors to estimate AC and SAC over the coming year to better inform our pricing decisions. We consider that prices are only likely to fall below AC for customers with very low levels of annual consumption. This is partly due to the impact of LFC Regulations, which limits the recovery of cost reflective charges from domestic customers with low annual consumption. With the phasing out of restrictions beginning on 1 April 2022, Electra believes that this will alleviate any potential cross-subsidy as fixed charges will exceed AC.

Electra's pricing approach is to allocate costs between customer groups using cost-reflective allocators. This results in allocations that fall between SAC and AC on average on the basis that the cost allocators used represent the underlying network cost drivers.

Standalone Cost

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

From general publicly available analysis Electra has concluded that going 'off grid' is more expensive than grid supply. 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 customers.

For larger connections, standalone costs may depend on the location of the customer relative to the connection to the transmission grid (the GXP). We estimate that 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 that is likely to arise in relation to circuit length is between rural and urban customers, as rural customers have a longer circuit length than urban customers, and there is higher connection density in urban areas, leading to urban customers subsidising rural customers.

We do not consider disaggregating rural and urban customers for pricing purposes is beneficial for the following reasons:

- Rural circuits, poles, and equipment are also used by urban customers 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 so rural areas are 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 customers supplied by the relevant section of the network. Fault response times are similar for rural and urban connections because all connections are located within 30 minutes' drive from both depots

- 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 customers by not differentiating between urban and rural customers.

New connections in remote rural areas is 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 customers can be very expensive. Electra has a relative compact network and dense network meaning this example is relatively uncommon.

Avoidable Costs

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

ii. reflecting the impacts of network use on economic costs

Pricing structures are economically efficient where they assist to signal the economic costs of servicing different customer profiles. A customer 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

Electra has recently adopted ToU pricing for our small and medium customer groups to better signal the economic costs of future capacity investments. Legacy pricing approaches based on kWh consumption are inefficient in that they provide an incentive for customers to reduce consumption overall and are relatively poor at signalling economic costs. Disaggregating consumption by peak, shoulder and off-peak periods will help Electra to better reflect economic costs associated with future capacity investments, as discussed in Section 4.

Connection capacity

Differences in connection capacity costs are reflected in the small medium and industrial pricing category. Small and medium customers are generally connected to LV networks whereas industrial is connected to high voltage assets.

Streetlights

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

Load control

Electra controls hot water heaters connected to the network. This control reduces congestion on the network and the transmission grid at times of peak use and helps to reduce prices for customers. We provide a discount on 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 customers.

Night only and night boost

A night only and night boost pricing option applies discounted prices to permanently wired and separately metered equipment that is 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 customers to use network capacity during off-peak periods when the cost of network use is low. Similarly, night boost allows for energy to be used between 1pm and 4pm at the shoulder period when the network is less congested.

Dedicated assets

Large Industrial customers are charged for dedicated assets directly.

Power factor premium

Where the power factor is less than 0.95 Electra reserves the right to impose a power factor premium on commercial customers. This recognises that 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. reflecting differences in network service provided to (or by) consumers

The key service that Electra provides is access to the network. Distinctions are made in pricing for type of end-customer, time of use, capacity size, and asset specification. Specific examples of different network offerings in Electra's Pricing Methodology are similar to those highlighted in our response to the previous principle and include:

- Connection capacity size are reflected in our small, medium and Industrial customer groups and through capital contributions
- Time of use services are provided for through our ToU, night and night boost pricing structures
- Electric Vehicles and DER, now have a separate pricing option targeted to their needs through 'ToU + EV' and Export pricing
- Streetlights are charged specifically for their assets
- Unmetered loads have separate prices reflecting the varying circumstances of these connections and lack of metering information
- Non-standard asset specifications and load sizes are catered for through industrial and non-standard pricing.

iv. encouraging efficient network alternatives.

Network prices should also generally fall below the standalone cost of network alternatives in order to disincentive inefficient bypass of the network. As discussed in Principle A i), average charges are estimated to be less than SAC for all customer groups. Therefore, they discourage customers from investments in inefficient off-grid energy solutions.

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 relatively limited at present 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 in order to give customers information on which to make 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 a winter evening. Anytime consumption charges encourage inefficient investments in Solar PV as customer charges decrease with onsite generation, but costs to serve do not.

The ToU pricing structures we have recently introduced will be more effective at signalling efficient investments in network alternatives such as PV, as customers will be unable to 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 customers in line with the phase out of the LFC Regulations will also ensure that every customer pays a minimum contribution to network costs, despite their level of consumption. This recognises that customers with solar still contribute to the cost of serving peak demand.

Principle 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

Residual costs are the remaining costs to recover from prices after deducting revenue that is 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 Electra. These residual cost should be recovered through non-distortionary pricing mechanisms in accordance with Principle B.

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

Until recently, the LFC Regulations have limited how much revenue can be recovered from domestic low users, which make up the majority of our customer base. Electra's pricing strategy involves increasing the proportion of revenue from fixed charges consistent with the 5 year phase out of the LFC Regulations. Overtime 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

Electra's pricing reflects different network service offerings that are responsive to the needs of customers. Customers 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.

AC and SAC form the boundaries within which prices are negotiated and set to ensure services reflect fair economic value.

Prices above SAC are unlikely to be sustainable in a market for alternative energy sources and may result in inefficient bypass of the existing infrastructure. Electra's prices are set below SAC. Electra sets prices above AC for each customer group, and would seek to do this for any non-standard connections, therefore recovering the economic cost of supply for each customer group.

ii. enable price/quality trade-offs

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

- ToU, Night and Night Boost pricing allows customers to select pricing options that allow them to make trade-offs on when they use electricity
- Controlled pricing plans have lower prices to recognise that the network can turn off customer hot water load to manage network load
- Electra is 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

Electra's pricing is simple and is limited to fixed daily and variable consumption prices for the majority of customers.

Electra's Pricing Methodology and annual price changes are published on its website. These disclosures provide relevant information that customers and retailers need to understand how prices are set.

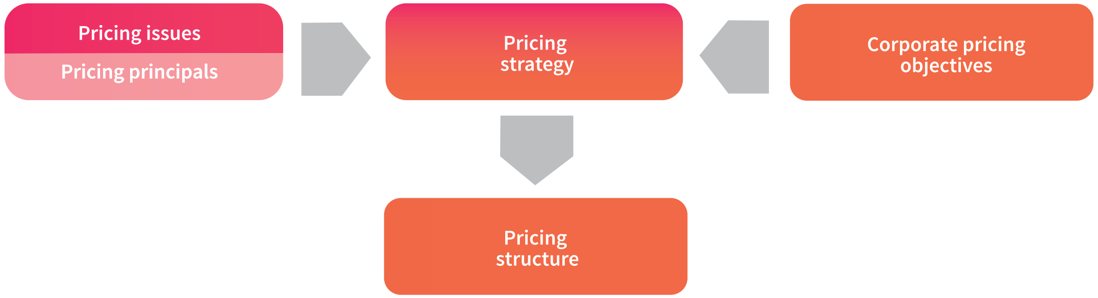
We have sought to reduce retailer transaction costs by developing pricing to reflect industry standard terminology, customer profiles and connection characteristics, where possible.

Appendix Two:

Electra pricing objectives

Introduction

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



	Corporate pricing objective	Supports Electra with….
Efficiency objectives	1. Price structure should be consistent with the long-life assets and the long period over which Electra will recover its costs	Delivering sustainable returns over the long-term
Efficiency objectives	2. Electra's prices should encourage the efficient use of, and Electra's efficient investment in, the network	Improving efficiency and maintaining competitiveness
Efficiency objectives	3. Prices should not impede the implementation of new technology	Facilitating innovation that improves efficiency
Fairness objectives	4. Price changes should consider the impact of large (upward and downward) short-term variations in the charges seen by individual customers or classes of customers	Fairness to customers
Fairness objectives	5. For each class of customer, prices should fairly reflect costs of providing the service to those customers	Fairness to customers
Fairness objectives	6. Prices should change gradually over time	Fairness to customers
	7. The pricing structure shall comply with relevant legal and regulatory requirements	Being a good corporate citizen

Corporate pricing objectives

Electra's Statement of Corporate Intent ('SCI') defines the overall direction and performance expectations for the Electra Network. For the SCI we have developed a series of corporate pricing objectives. These are statements that we believe the pricing strategy needs to be 'tested' against to ensure that it will satisfy Electra's corporate objectives.

Appendix Three:

Glossary

We have sought to present our Pricing Methodology using standard industry terminology and to include sufficient information to enable pricing decisions to be readily understood by customers. This glossary is provided for the convenience of the reader.

Term	Meaning
2020/21	The year starting 1 April 2020 and ending on 31 March 2021.
2021/22	The year starting 1 April 2021 and ending on 31 March 2022.
2022/23	The year starting 1 April 2022 and ending on 31 March 2023.
ACOT	Avoided Cost of Transmission: The difference between actual transmission costs and theoretical transmission costs if certain mitigation (e.g. Distributed Generation) is not present.
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 an ICPs connection and related equipment needed for its energy demand. This charge covers the cost of the assets involved in supplying electricity.
Coincident Maximum Demand (CMD)	Relative demand (kW or kVA) of a particular customer or customer group at the GXP system peak (i.e. as measured by system maximum demand).
Commerce Commission (ComCom)	Responsible for the economic regulation of electricity distribution businesses as provided for under Part 4 of the Commerce Act 1986.

Term	Meaning
DER	Distributed Energy Resources, typically roof top solar, wind driven generators, car to grid.
ICP	ICP means an installation control point being 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, issued 1 October 2012 (Decision No. NZCC22).
kVA	Kilo Volt-Amp: Measure of apparent electrical power usage at a point in time.
kWh	Kilowatt hours: Measure of real electrical power usage per hour.
Low fixed charge regulations (LFC)	As set out in the Electricity (Low Fixed Price Option for Domestic Customers) Regulations 2004. These require Electra 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 15 cents (excl. GST) and customers should be no worse off under this price option at 8,000 kWh relative to other prices.
Power Factor	The ratio of real power (e.g. kW) to apparent power (e.g. kVA). 0.98 is considered normal on our network.
PowerSwitch	PowerSwitch is an EA funded independent service that helps customers work out which power company and pricing plan is the cheapest.
PV	Photovoltaic – electricity generating solar panels.
RCPD	Regional Coincident Peak Demand: Transpower calculates its interconnection charge for each GXP by its relative share of RCPD.
Retailer	Electricity retailer that Electra supplies.

Term	Meaning
Sub-transmission	A power line that transports or delivers electricity at 33 kV on Electra’s network.
System Maximum Demand	Aggregate peak demand for the network, being the coincident maximum sum of GXP demand and embedded generation output.
Target revenue requirement	The revenue to be recovered through prices over the pricing year in order to recover Electra’s 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 by 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.

Electra
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