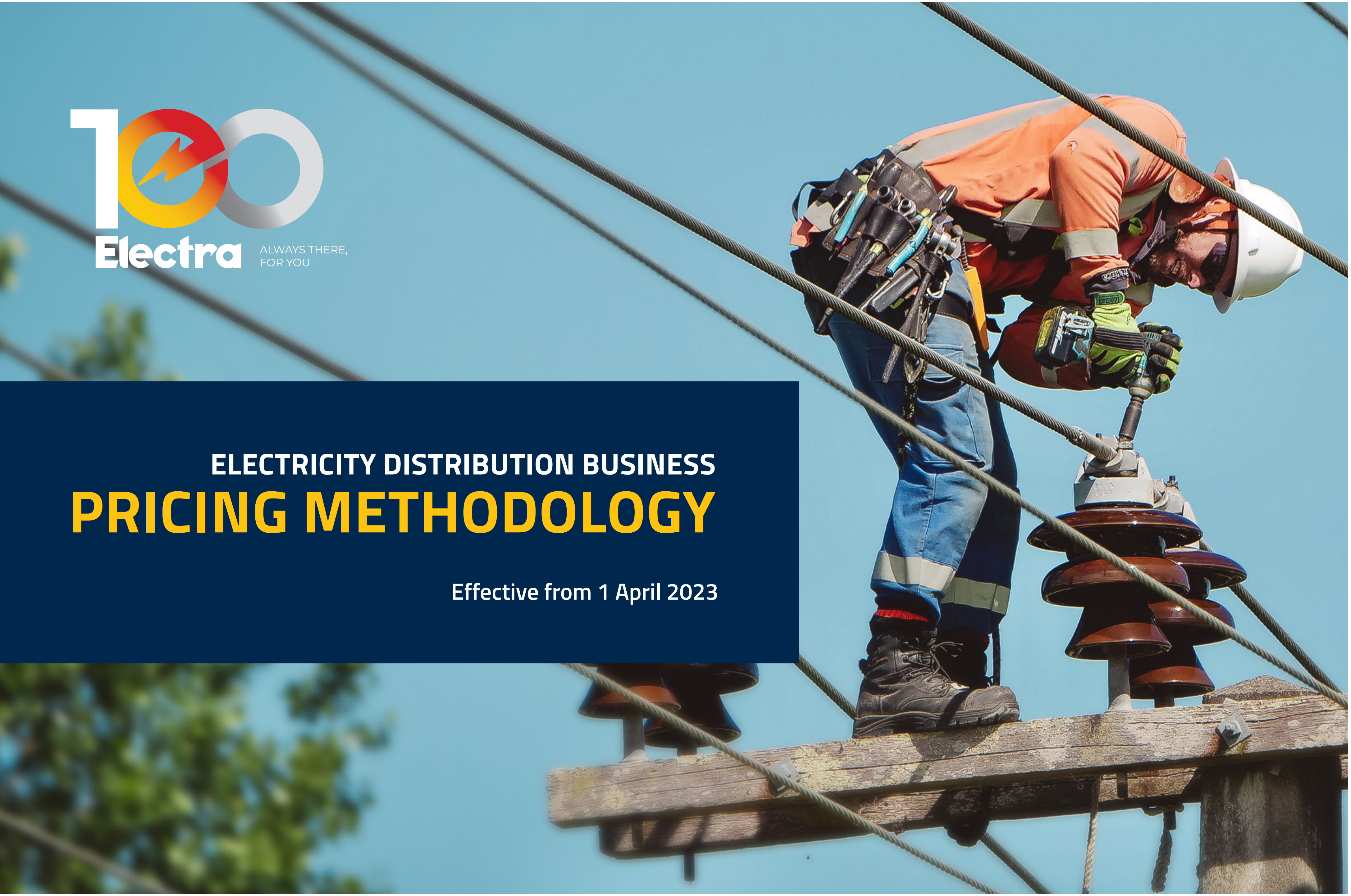


Electra
ALWAYS THERE, FOR YOU

ELECTRICITY DISTRIBUTION BUSINESS

PRICING METHODOLOGY

Effective from 1 April 2023

Contents


DHT-145AS
MAX. WIND SPEED 12M/S

1. Overview

This document describes the approach we use to set our electricity distribution prices that apply from 1 April 2023. 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 change 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. We endeavour to ensure the operation of the network, and the services we provide (and the prices we charge for those services), are appropriate to meet customers' needs.

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

We expect a positive benefit from the Waka Kotahi, New Zealand Transport Agency, completing two regional roading projects and preparing for the Ōtaki to North of Levin segment: Transmission Gully which opened in March 2022 and the Peka Peka to Ōtaki project which opened in December 2022. Transmission Gully is providing improved travel times in and out of Wellington and surrounding areas, with a prediction this will 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 other industries relocating here. Marking a significant change to our existing majority of low-use domestic customers.

Sustainability

We are committed to supporting the Government's 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 considered a critical asset in supporting activities such as the electrification of transport and the removal of carbon-based process heat.

We have a volunteer sustainability action group comprised of employees from all parts of the organisation who guide sustainability activities. As a corporate entity, we participate in local and national working groups (Climate Change Commission, NZ Battery Project, and EV Connect) supporting decarbonising opportunities.

We aim to support New Zealand's Carbon Neutral Government Programme through prices by providing pricing plans for export charging and EV tariffs.

Time of Use (ToU) pricing encourages customers to shift load to times when there is spare capacity, avoiding unnecessary augmentation of our distribution network. Our focus on having capacity available where and when consumers want on a least-cost basis is reflected in our annual Asset Management Plan (AMP) through our support of disruptive technologies such as DER and greater numbers of EVs. Over the next three years Distributed Energy Resource Management (DERMS) and flexibility services systems will enable us to better plan and demonstrate the ability to manage increased electrification. This will help us to manage the cost to serve being in the long-term best interest of our consumers.

COVID-19

Covid-19 has continued to impact staff, customers, and business operations. We continue to respond efficiently, utilising work practices honed over the pandemic, delivering an essential service and the AMP programme. It is anticipated 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

We will continue to adapt our pricing as technology and customer behaviours change. Accordingly, a pricing strategy has been developed to guide the development of our electricity distribution prices over the coming years.

- We 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. we 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 we believe will provide the foundation to manage the impact of the growth in alternative energy sources and seeks to ensure the correct allocation of costs across customer groups.

The changes to prices from 1 April 2023 continue this evolution

Prices from 1 April 2023 include several changes consistent with the pricing strategy. Key changes to prices for this coming year are set out in Table 1 below.

Objective	Action	Impact on customers
Change to low user fixed charge	Increase low user fixed daily charge to $0.45 (up $0.15 from 2022/23).	Continued potential for energy hardship
Removal of SRAM cost reduction	The removal of the loss and constraint payments by the EA in the SRAM changes	Continued potential for energy hardship
Simplify Pricing	Close price options (C, CA, N, XTNO) that are price matched and duplicates of other prices.	No impact on consumers

Our Pricing Methodology complies with the regulatory requirements

The Pricing Methodology has been reviewed against the relevant regulatory requirements and has considered the nature of the network and the practical evolution of our prices to manage disruptive change for customers. We consider our pricing approach complies with the following:

- The Electricity Authority's Pricing Principles
- The Electricity Authority's Distribution Pricing: Practice Note, Edition 2.1, 2022
- 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 to apply from 1 April 2023

Table 2 sets out the network prices that will apply from 1 April 2023 with a comparison of changes from 2022 prices. For further information, please see our published pricing schedule on our website at https://electra.co.nz.

Low Users (<=8,000 KWH PER YEAR)

	CODE	DESCRIPTION	CUSTOMERS	UNIT	PRICE 01/04/22	PRICE 01/04/23
GENERAL PRICING	F	Fixed daily	23,671	$/day	0.3000	0.4500
	A	Uncontrolled/Anytime		$/kWh	0.1260	0.1400
	DN	Night of Day/Night (9pm-7am)		$/kWh	0.0690	0.0770
	DD	Day of Day/Night (7am-9pm)		$/kWh	0.1450	0.1660
	M	Controlled 20 (electric hot water)		$/kWh	0.0720	0.0840
	N	Night only (11pm-7am)		$/kWh	0.0680	0.0740
	B	Night Boost (11pm-7am & 1pm-4pm)		$/kWh	0.0690	0.0780
TOU PRICING	TF	Fixed daily	14,667	$/day	0.3000	0.4500
	TN	Off-Peak (11pm-7am)		$/kWh	0.0680	0.0740
	TP	Peak (7am-11am & 5pm-9pm)		$/kWh	0.1270	0.1460
	TO	Shoulder (11am-5pm & 9pm-11pm)		$/kWh	0.1000	0.1110
	M	Controlled 20 (electric hot water)		$/kWh	0.0720	0.0840
	B	Night Boost (11pm-7am & 1pm-4pm)		$/kWh	0.0690	0.0780
TOU + EV PRICING	TEVF	Fixed daily	11	$/day	0.3000	0.4500
	TEVN	Off-Peak (11pm-7am)		$/kWh	0.0520	0.0670
	TVEP	Peak (7am-11am & 5pm-9pm)		$/kWh	0.1270	0.1460
	TEVO	Shoulder (11am-5pm & 9pm-11pm)		$/kWh	0.1000	0.1110
	TEVM	Controlled 20 (electric hot water)		$/kWh	0.0720	0.0840

Standard Users (>8,000 KWH PER YEAR)

	CODE	DESCRIPTION	CUSTOMERS	UNIT	PRICE 01/04/22	PRICE 01/04/23
GENERAL PRICING	AF	Fixed daily	2,436	$/day	1.0800	1.3100
	AA	Uncontrolled/Anytime		$/kWh	0.0910	0.1010
	DNA	Night of Day/Night		$/kWh	0.0340	0.0380
	DDA	Day of Day/Night		$/kWh	0.1100	0.1270
	MAA	Controlled 20 (electric hot water)		$/kWh	0.0370	0.0450
	NOA	Night only		$/kWh	0.0330	0.0350
	BA	Night Boost		$/kWh	0.0340	0.0390
TOU PRICING	XTF	Fixed daily	5,424	$/day	1.0800	1.3100
	XTN	Off-Peak (11pm-7am)		$/kWh	0.0330	0.0350
	XTP	Peak (7am-11am & 5pm-9pm)		$/kWh	0.0920	0.1070
	XTO	Shoulder (11am-5pm & 9pm-11pm)		$/kWh	0.0650	0.0720
	XTM	Controlled 20 (electric hot water)		$/kWh	0.0370	0.0450
	XTB	Night Boost		$/kWh	0.0340	0.0390
TOU + EV PRICING	XTEVF	Fixed daily	5	$/day	1.0800	1.3100
	XTEVN	Off-Peak (11pm-7am)		$/kWh	0.0170	0.0280
	XTEVP	Peak (7am-11am & 5pm-9pm)		$/kWh	0.0920	0.1070
	XTEVO	Shoulder (11am-5pm & 9pm-11pm)		$/kWh	0.0650	0.0720
	XTEVM	Controlled 20 (electric hot water)		$/kWh	0.0370	0.0450

Industrial (>40,000 KWH PER YEAR)

CODE	DESCRIPTION	CUSTOMERS	UNIT	PRICE 01/04/22	PRICE 01/04/23
S	Fixed daily	265	$/day	2.3400	3.1000
SN	Off-Peak (11pm-7am)		$/kWh	0.0260	0.0230
SP	Peak (7am-11am & 5pm-9pm)		$/kWh	0.0740	0.0810
SO	Shoulder (11am-5pm & 9pm-11pm)		$/kWh	0.0510	0.0560
SCAP	Capacity		$/kVA/day	0.0000	0.0000

Unmetered

CM	Maintenance fee		$/fitting/day	0.2300	0.2400
U	Unmetered/Streetlighting		$/kWh	0.1300	0.1500
LGT	Lighting		$/fitting/day	0.2300	0.2400
LGTU	Lighting Consumption		$/kWh	0.0000	0.0000

Export

EX	Small scale distributed generation	1,160	$/kWh	0.0000	0.0000

2. Introduction

Across the network, we deliver around 418 Gigawatt hours (GWh) of electricity each year from the national grid to approximately 47,000 customers.

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

Our customers in Horowhenua and Kāpiti districts own us through the Electra Trust. The trustees appoint directors and hold 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.

We receive electricity at 33kV from the national grid via two Transpower Grid Exit Points (GXP). Our northern area (Horowhenua) connects to the Mangahao GXP, and the southern area (Kāpiti) connects to Paraparaumu GXP. While there is no continuous connection between these GXPs, our electricity distribution network accommodates a choice of points for the north-south split. We currently treat our networks 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 although a very small number of large customers are supplied at 11kV.

Overlaying the network, our 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
Waitārere Beach
Shannon
Mangahao
Hōkio Beach
Ohau Beach
Levin
Kuku 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

3. Regulatory Context

Commerce Act

We are incentivised to deliver an efficient and reliable service to our customers as a customer-owned distribution business. Our exempt status was recognised in 2008 when we were exempted from price-quality regulation applying to electricity distribution networks under Part 4 of the Commerce Act 1986 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 Commerce Commission's Information Disclosure Determination requirements.

Electricity Authority

We have developed our prices with reference to the Electricity Authority's Pricing Principles (Pricing Principles) and Practice Notes. The purpose of the Pricing Principles is to ensure prices are based on a well-defined, clearly explained, and economically rational methodology. These principles guide economic concepts and market considerations, which apply to setting efficient network prices.
The Disclosure Determination requires each Electricity Distribution Business to demonstrate consistency with the Pricing Principles or explain the reasons for any inconsistency.

Appendix 1 sets out the Pricing Principles and comments on the extent to which our Pricing Methodology is consistent with them.

Low Fixed Charge Regulations

As distributors, we are subject to the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 (LFC Regulations). The Electricity Authority monitors and enforces these regulations. The regulations require us to offer residential consumers a price option at their primary place of residence with a fixed price of no more than 45c 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 consumers 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 LFC regulations over the following five years.

Electricity Code

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

4. Pricing Strategy

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

Part of our pricing strategy is to introduce and refine service-oriented and cost-reflective pricing progressively, to recover the network's economic costs and be responsive to the evolving market and the changing ways customers use our 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 in the future. The adoption of ToU pricing is a key step in this strategy. As we evolve, this will involve an iterative process of fine-tuning pricing signals and building the capability to measure and interpret the impact of changes in use. Pricing is one tool we have. We will also investigate alternatives to capital works programmes, such as developing flexibility services instead of network upgrades.

As a network, we are dominated by low-user customers. Accordingly, the most significant aspect of our pricing strategy will be transitioning away from LFC Regulations in the next five years. With no significant capacity constraints on the network, it has been incongruous with the Pricing Principles that so little of our revenue is recovered from fixed charges. To align with the Pricing Principles, we plan to increase the low-user fixed charge consistent with the Government's phase-out plan. Our approach will progressively allow a higher proportion of revenue to be recovered from fixed charges to lessen the distortion currently caused by the LFC Regulations.

Huringa Pūngao

In June 2021, we started Huringa Pūngao, our energy transformation roadmap to 2040. We have created an Energy Transformation Working Group tasked with developing and implementing the roadmap. The roadmap considers the effects on assets from decarbonisation actions to mitigate climate change. The intent is to follow a low-cost, low-risk pathway, substituting building more infrastructure with the 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, including the expected costs of flexibility services.

The use of DER is continuing to increase, albeit from a very low base. There are approximately 940 generation connections on our network. Representing 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, DER penetration across our networks 'footprint is forecast to reach 20% by 2042; on an increased ICP count of 61,800 (from around 46,000) and over the same period, EV penetration is expected to reach 75%.

Technological innovation and adopting new products for networks and customers will improve reliability, customer service, and convenience. Independent analysis estimated that the maximum value of flexibility services (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 our 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 reflect better the economic costs of connecting new load, DER, and EVs to the network. We will also need to plan for a future where we can no longer access demand control. If access to demand control remains, it is anticipated that we 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 that build capability while keeping options open. It is expected that in three years, we will be well on our way to demonstrating resilience and active participation in facilitating the required changes in the energy landscape. The additional expenditure requirements to meet this capability-building plan over these next three years are not material, adding 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

Capability-building facilitates accurately assessing 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.

We plan to make the necessary changes in the coming years to align its methodology with the Pricing Principles better. Further information on how our pricing methodology is consistent with the Pricing Principles is provided in Appendix One.

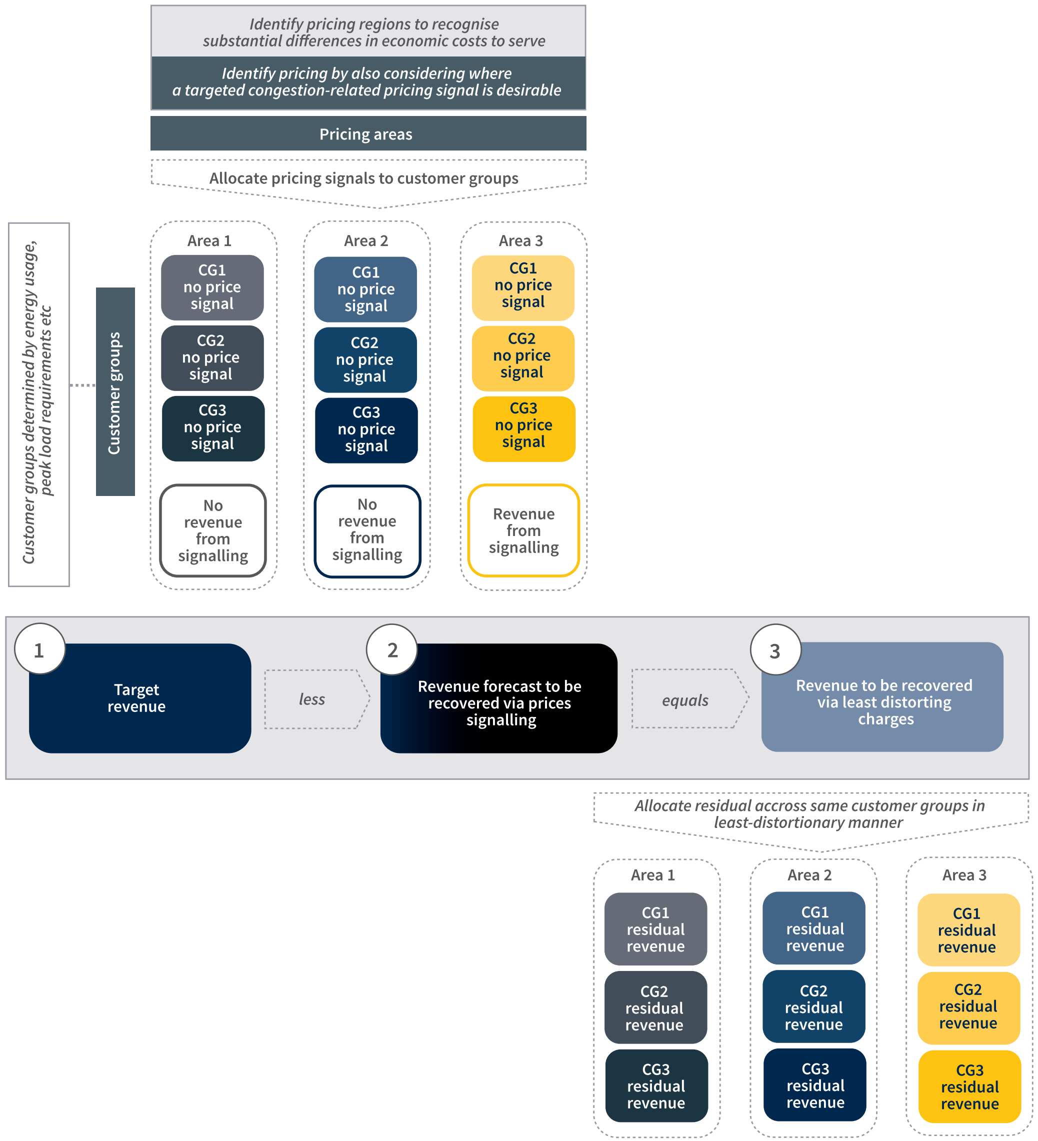
Our primary service is to have the desired capacity available on our network when and where our customers want it. Typically, this reflects the maximum amount of energy that can be transmitted through our network at a point in time to serve a customer. Cost-reflective pricing should target when network capacity is congested to signal to users the future economic costs of upgrading capacity.

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

While most of our network is not currently constrained, recently completed transport links to Wellington, reducing travel times to the Kāpiti and Horowhenua regions, are likely to stimulate population growth that could result in emerging constraints. In 2022 we introduced a ToU pricing option that will help to signal peak usage periods before a physical constraint on the network arises.

ToU pricing sends a signal that allows customers to become aware of the periods when the network is most constrained. It also gives us the tools to respond quickly to network usage and demand changes. The forecast growth on our network is driven by population growth (ICPs) and DER uptake, making it prudent to introduce these tools early.

A lack of data and analytical capacity has meant that assessing proportionate cost signalling has had to be done by empirical methods to this point.



The Cost of Supply model

The cost to supply model continues to be improved as we look to refine our cost drivers, including the economic costs of serving different consumer groups, through estimates of avoidable costs (AC), residual costs, and standalone costs (SAC). Using information about our cost drivers, we will refine price signals for ToU pricing and consider optimal balances of fixed charges better to align pricing with economic and residual costs concepts.

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 we send through our ToU and Day/Night differentials will need to vary each year to determine the long run optimal setting. Nevertheless, implementing this pricing has continued to improve understanding of customer behaviour, and refining this signal will continue as described above.

Customer impact

We assess the impact of each change to the price structure and price level on customers by taking into account the following:

- 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 new price structure.

The price impact is assessed by examining the average change in price for all customers. We engage with retailers about how changes might impact their customer bills.

Across our network, individuals, households, and whanau face energy hardship in their homes or kāinga. We have 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. Customer positioning will be particularly important in the next four years as the LFC Regulations continue to be phased out. The majority of our customer base will be affected by these changes. We will continue working to rebalance the variable proportion of target revenue to mitigate these increases in low-users. However, in the interim, our focus is actively encouraging customers to use services like Powerswitch to help reduce their overall electricity bill.

Progress on the Pricing Roadmap

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

Electra Pricing Roadmap

2023/24	2024/25	2025/26	2026/27	2027/28
• 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 • Consult on ToU as default plan • Implement TPM and SRAM	• 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 • Consider capacity pricing	• Review impact of removal of LFC • Update pricing methodology to include flexibility services • Prepare for possible capacity pricing

5. Pricing Methodology

We have maintained the same approach to set prices for 1 April 2023 as we used to set our 1 April 2022 prices. The key steps in our price-setting process include the following:

1. Determine the amount of target revenue to be recovered via prices over the pricing period (1 April 2023 – 31 March 2024) through consideration of budgets, asset management plans, and customer impacts (Section 6).

2. Review and confirm customer groupings (section 7) and pricing structures (Sections 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 (Sections 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).

6. Target Revenue

We determine our target revenue requirement from our Asset Management Plan and 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.

The target revenue (inclusive of the discount) recovered through prices is $53.2m for the year ending 31 March 2024. The target revenue is $7m up on the FY2023 budget due to increasing operating costs, including but not limited to network growth, regulatory change and inflation.

Price Changes

As a result of an increase in target revenue, overall prices will increase for customers in 2024.

Distribution charges make up around 79% of total network charges for customers. These have increased for 2023 by an average of 2.6%. The increase reflects the annual change to our target revenue, which we target to be in line with our peer EDBs which the Commerce Commission regulates. We note that most regulated companies are generally accumulating revenue shortfalls, leading 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 11%. We expect the average residential customer’s distribution bill to increase by around 16%.

Additionally, we have continued year two of the change linked to removing the LFC Regulations. We expect to incrementally increase our low user fixed prices by $0.15 per year (15 cents) over the next four years.

Type	Component	2023 forecast $m	2024 forecast $m
Distribution	Operating Expenditure	16.8	20.0
	Sales Discount	5.1	5.2
	Depreciation	10.6	14.9
	Regulatory Tax Allowance	1.6	2.7
	Revaluations	(3.2)	(7.55)
	Other Regulated Income	(1.2)	(1.6)
	Return on Investment	5.2	7.5
Pass Through	Transmission	9.6	12
	Rates & Levies	0.04	0.05
Total		44.5	53.2

Other changes to our pricing

1. Additional price options: based on the feedback from our retailer consultation in 2022, we have removed All Inclusive from general pricing, and Night only from our TOU price options.

2. Rebalance—as part of our price model review; we have identified the need to correct the differential in our ToU options to better align with best practice discount/premium concepts. The result is an increase in the Day and Peak prices, and a decrease in the Industrial Off-Peak. For Low users and Industrial users, we have ensured cost recovery via the fixed price components.

3. New Post Discount Prices—from 1 April 2022, we will publish post discount prices to meet our obligations outlined in the Default Distributor Agreement under Schedule 10. We will use the post-discount prices to calculate the discount owed to customers, which is administered in February each year.

Network growth

Over the last five years, we have seen a 4% growth in consumption at the GXP level. For FY2024, this translates to a target of 430m units billed compared with 422m budget in FY2023.

The continued increase in GXP consumption combined with the stabilisation in non-technical losses for FY2023 has contributed to the increase in target revenue for FY2024.

7. Consumer Groups

The basis for the customer groupings we have adopted in our 2023/24 pricing methodology is unchanged from last year.

We established the three primary customer groups as part of our 2013 pricing review. During our most recent pricing strategy review, we reviewed these customer groups and considered that they remain unchanged in the current phase of our pricing roadmap.

Street lighting and community lighting are separate customer groups. Separate customer groups recognise these connections use dedicated assets (i.e. streetlight circuits) and have unique demand profiles (i.e. at night).

8. Customer Considerations

Customer ownership

Our customers own us 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 survey our customers to understand their views on prices, quality of supply, and consumption patterns. In 2022, 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:

The survey highlighted customers' continued requirement to receive up-to-date information on outages. How long the power outage will be, and when will it be back on? The number of respondents that reported regularly working from home has dropped from 42% to 24%, which is in line with 2020 numbers.

The survey also highlighted customers' growing interest in alternative energy forms, with 14% of respondents indicating they had installed solar photovoltaic (PV) supply and 50% suggesting purchasing a system. PV installation creates commercial and operational challenges and opportunities for the network. In addition to PV's, there is significant interest in purchasing an EV. 44% residential and 52% of commercial respondents suggested they considered an EV instead of an ICE vehicle, with 8% residential and 18% commercial respondents already purchasing an EV.

The price signals have been adjusted from last year to be more consistent across price categories and more appropriate to the level of network constraint. We expect this to be an ongoing exercise, as the rebundling of price options means that not every customer sees and responds 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.

9. Cost Drivers

Overview of network attributes that influence our costs

We apply the relevant cost drivers and seek to recover those based on customer groupings, price structures, and charge levels.

Our costs are associated with investing in, maintaining, and operating the network and taking supplies 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 the 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.)	47,000
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)	424
Energy density (kWh/ICP)	9,000

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 seen in the table above, our maximum network demand of 111 MW is well below the zone substation installed capacity of 352 MW. This broad measure indicates the network is not constrained at its key nodes. However, there is a Transpower imposed terminal constraint at our Mangahao GXP, the limit of 38MW means that at times during winter peak periods we use load control to ensure we are below the constraint.

During the 2021 winter peak, we 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 in our AMP and are under review as part of our Energy Transformation Working Group.

Circuit length

The circuit length required to transmit electricity from the GXP to customers is a key driver of network investment costs. Customers from the main supply areas create relatively higher costs for us. However, compared with other NZ networks, our network is relatively compact. Further, the ongoing meshing of the distribution network in urban centres and rural areas makes it difficult to distinguish line lengths for a particular customer or group of customers (due to the difficulty in tracking electrical flows). While customer 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. Our Network Extension Policy requires customers to pay for connection-related asset costs upfront. This policy and the associated contribution model are under review at the time of writing. Each new connection also incrementally increases network operations and planning costs, fault restoration, maintenance, and general administration.

Customer-specific asset usage

Where practical, the network costs related to a particular customer or group of customers are identified and recovered from those parties. Our approach aligns cost recovery 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 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 to reflect the costs of dedicated equipment. For those customers that require dedicated equipment, this has generally been dealt with as part of our network extension policy rather than through pricing. In the future, the network extension policy and pricing will be combined to have more cost-reflective pricing and asset allocation.

10. Allocation of Target Revenue to Consumer 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 consumer group. The allocators reflect how the different consumer groups drive the cost components.

Budget item	Choose from list
Transmission Charges	kWh & ICPs
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 the target revenue forecast (net of transmission) to be recovered from each price option in the 2023/24 pricing year.

Category	Target Cost Allocation	Estimated Consumption	Customer Count
Non-TOU (F, AF)	$16.0m	192.3m	25,936
TOU (TF, XTF)	$17.5m	147.4m	20,109
EV TOU (TEVF, XTEVF)	$0.07m	0.04m	12
Industrial (S)	$4.9m	90.2m	264

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

- Interconnection Charges: based on our 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 we receive supply from the grid
- New Investment Agreement Charges: with new connection assets

Transpower also calculates losses and constraints excess (also known as SRAM) and returns this to distributors over the pricing year. In prior years this has been returned to the retailers through pricing. As these are not known when prices are set, we had estimated the amount annually and provided a credit against the transmission cost driver. Direction from the EA requires us to return the credits directly to the retailers through a credit pass through. This has caused an increase in the overall transmission costs.

We are responsible for paying all transmission charges associated with the Mangahao GXP, including the avoided cost of transmission (ACOT). There is a generating station located at Mangahao, which reduces the demand placed on the transmission network (by reducing the RCPD at the GXP) and the total charges payable to Transpower for transmission services. In recognition of this service, we pay the Mangahao power station a share of the savings (i.e. an ACOT). We also retain some of these savings, which benefits our network customers.

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

The new methodology has removed the use of RCPD to calculate the Interconnection Charge and introduced the following charges:

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

The new charges are designed so consumers pay for the transmission assets and investments they benefit from. This sends clear signals to consumers and reducing inefficient grid investment and grid use.

Transpower's charges have increased for 2023/24.

Operating costs

The operating and maintenance costs included in the target revenue are obtained from our Asset Management Plan (AMP) forecasts. Our AMP details plans for our network's maintenance and development, including forecast cost for these activities. Operating and maintenance costs have increased in FY2024 due to the increase in costs from our suppliers and contractors.

Administration and overheads

Administration and overhead costs are incurred in running our network business activities. These costs are driven by our requirement to manage the business's non-engineering aspects, including 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 expenditures required to ensure the resiliency of the ICT network.

Depreciation and return on investment

Depreciation reflects the “return of capital” from the consumption of the economic life of the network assets. This charge is a standard depreciation calculation based on the useful economic life of the assets. This return allows us to replace assets as they near the end-of-life 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 FY2024 is higher than FY2023 due to increases in our asset base driving higher depreciation, offset by the recognition of disposals that result from planned renewal projects.

11. Price Options and Design

Prices for 2024

Post-discount prices for 2024 will also be disclosed. Customers will still receive their fixed discount of $31 (pro prorated by connected days), and the remaining discount will be calculated based on their variable (kWh consumption).

The discount eligibility rule of connecting to our network on 31 January remains.

Low Users (<=8,000 KWH PER YEAR)

	CODE	DESCRIPTION	CUSTOMERS	UNIT	PRICE 01/04/22	PRICE 01/04/23	POST DISCOUNT
GENERAL PRICING	F	Fixed daily	23,671	$/day	0.3000	0.4500	0.3650
	A	Uncontrolled/Anytime		$/kWh	0.1260	0.1400	0.1312
	DN	Night of Day/Night (9pm-7am)		$/kWh	0.0690	0.0770	0.0682
	DD	Day of Day/Night (7am-9pm)		$/kWh	0.1450	0.1660	0.1572
	M	Controlled 20 (electric hot water)		$/kWh	0.0720	0.0840	0.0752
	N	Night only (11pm-7am)		$/kWh	0.0680	0.0740	0.0652
	B	Night Boost (11pm-7am & 1pm-4pm)		$/kWh	0.0690	0.0780	0.0692
TOU PRICING	TF	Fixed daily	14,667	$/day	0.3000	0.4500	0.3650
	TN	Off-Peak (11pm-7am)		$/kWh	0.0680	0.0740	0.0652
	TP	Peak (7am-11am & 5pm-9pm)		$/kWh	0.1270	0.1460	0.1372
	TO	Shoulder (11am-5pm & 9pm-11pm)		$/kWh	0.1000	0.1110	0.1022
	M	Controlled 20 (electric hot water)		$/kWh	0.0720	0.0840	0.0752
	B	Night Boost (11pm-7am & 1pm-4pm)		$/kWh	0.0690	0.0780	0.0692
TOU + EV PRICING	TEVF	Fixed daily	11	$/day	0.3000	0.4500	0.3650
	TEVN	Off-Peak (11pm-7am)		$/kWh	0.0520	0.0670	0.0582
	TVEP	Peak (7am-11am & 5pm-9pm)		$/kWh	0.1270	0.1460	0.1372
	TEVO	Shoulder (11am-5pm & 9pm-11pm)		$/kWh	0.1000	0.1110	0.1022
	TEVM	Controlled 20 (electric hot water)		$/kWh	0.0720	0.0840	0.0752

Standard Users (>8,000 KWH PER YEAR)

	CODE	DESCRIPTION	CUSTOMERS	UNIT	PRICE 01/04/22	PRICE 01/04/23	POST DISCOUNT
GENERAL PRICING	AF	Fixed daily	2,436	$/day	1.0800	1.3100	1.2250
	AA	Uncontrolled/Anytime		$/kWh	0.0910	0.1010	0.0922
	DNA	Night of Day/Night		$/kWh	0.0340	0.0380	0.0292
	DDA	Day of Day/Night		$/kWh	0.1100	0.1270	0.1182
	MAA	Controlled 20 (electric hot water)		$/kWh	0.0370	0.0450	0.0362
	NOA	Night only		$/kWh	0.0330	0.0350	0.0262
	BA	Night Boost		$/kWh	0.0340	0.0390	0.0302
TOU PRICING	XTF	Fixed daily	5,424	$/day	1.0800	1.3100	1.2250
	XTN	Off-Peak (11pm-7am)		$/kWh	0.0330	0.0350	0.0262
	XTP	Peak (7am-11am & 5pm-9pm)		$/kWh	0.0920	0.1070	0.0982
	XTO	Shoulder (11am-5pm & 9pm-11pm)		$/kWh	0.0650	0.0720	0.0632
	XTM	Controlled 20 (electric hot water)		$/kWh	0.0370	0.0450	0.0362
	XTB	Night Boost		$/kWh	0.0340	0.0390	0.0302
TOU + EV PRICING	XTEVF	Fixed daily	5	$/day	1.0800	1.3100	1.2250
	XTEVN	Off-Peak (11pm-7am)		$/kWh	0.0170	0.0280	0.0192
	XTEVP	Peak (7am-11am & 5pm-9pm)		$/kWh	0.0920	0.1070	0.0982
	XTEVO	Shoulder (11am-5pm & 9pm-11pm)		$/kWh	0.0650	0.0720	0.0632
	XTEVM	Controlled 20 (electric hot water)		$/kWh	0.0370	0.0450	0.0362

Industrial (>40,000 KWH PER YEAR)

CODE	DESCRIPTION	CUSTOMERS	UNIT	PRICE 01/04/22	PRICE 01/04/23	POST DISCOUNT
S	Fixed daily	265	$/day	2.3400	3.1000	3.0150
SN	Off-Peak (11pm-7am)		$/kWh	0.0260	0.0230	0.0142
SP	Peak (7am-11am & 5pm-9pm)		$/kWh	0.0740	0.0810	0.0722
SO	Shoulder (11am-5pm & 9pm-11pm)		$/kWh	0.0510	0.0560	0.0472
SCAP	Capacity		$/kVA/day	0.0000	0.0000	0.0000

Unmetered

CODE	DESCRIPTION	CUSTOMERS	UNIT	PRICE 01/04/22	PRICE 01/04/23	POST DISCOUNT
CM	Maintenance fee		$/fitting/day	0.2300	0.2400	0.1500
U	Unmetered/Streetlighting		$/kWh	0.1300	0.1500	0.2400
LGT	Lighting		$/fitting/day	0.2300	0.2400	0.0000
LGTU	Lighting Consumption		$/kWh	0.0000	0.0000	

Export

CODE	DESCRIPTION	CUSTOMERS	UNIT	PRICE 01/04/22	PRICE 01/04/23	POST DISCOUNT
EX	Small scale distributed generation	1,160	$/kWh	0.0000	0.0000	

Explanation of our price options

Name	Description	Code	Price Component		Unit of measure
Residential / SME		Low, Standard			
Fixed Price	Daily fixed charge applicable to non-ToU 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	Customers may pay a lower price for hot water heating (and other uses) by allowing supply to be interrupted. We can switch the load off for up to 4 hours per day under this price.	M, MAA	n/a		dollar/kWh
Night	A night rate between 23:00 and 7:00 reflects the available capacity on the network during this period. The night rate does not function as a standalone option and must be on a circuit during these hours, used in conjunction with another price option for another load.	N. NOA	Night only	2300-0700	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 times of use prices: a night-time rate set for the 10 hours between 21:00 and 7:00; and a peak rate during the day.	DN, DNA	Night	2100-0700	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 ToU customers.	TF, XTF	n/a		dollar/day
Time of Use	A three-rate (peak, off-peak, and night) ToU option is available to all customers with the ability to move a load or otherwise take advantage of price signals. There is an additional option for a separately metered controlled load.	TN, XTN	Night	2300-0700	dollar/kWh
		TP, XTP	Peak	0700-1100	dollar/kWh
				1700-2100	dollar/kWh
		TO, XTO	Off peak	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

Our prices are focussed on the mass market (low and standard customer groups) because small loads dominate the customer base. Domestic and small commercial users represent approximately 98% of connections and over 80% of consumption. As a result, we have the lowest average use per connection of all New Zealand electricity distribution businesses (approximately 9,244 kWh per customer compared with 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 to large commercial loads. In contrast to the mass market, most large commercial loads have ToU metering and much higher annual consumption levels (ranging from 40,000 kWh to more than 3 GWh). Large commercial loads also have distinct demand behaviours: ranging from flat demand across the standard working day to highly variable demand that changes by time of day and season. From a cost driver perspective, large 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.

Specific prices in the low, standard, and industrial customer groups incorporate signals which enable customers to achieve a lower overall cost of supply by shifting consumption to off-peak periods and offering interruptible load. This aligns our pricing incentives to the cost of network capacity and capacity utilisation.

Each price 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. We intend to continue to evolve our pricing to recover costs via its fixed components. Together with our LFC price options, we offer a broad mix of options that:

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

ToU charge components

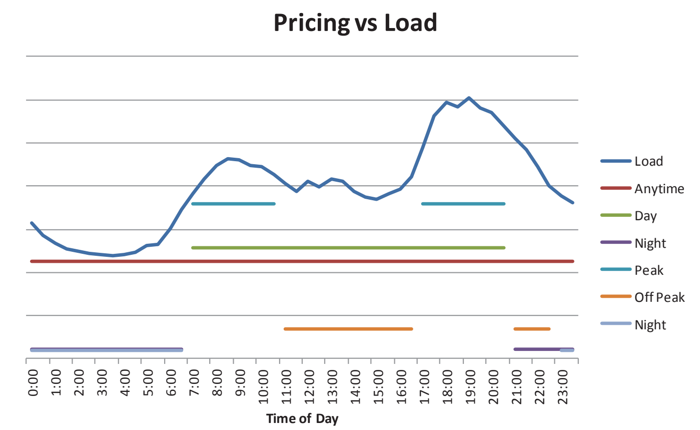
Several of our price options are designed to incentivise efficient use of our existing network capacity by setting higher variable prices at peak periods and lower prices during the shoulder and off-peak periods.

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

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

The figure below illustrates our ToU price options, usage periods, and how these pricing periods align with 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, such as the Controlled 20 or All-Inclusive price options, are also offered. 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.

We intend to review the total controlled price options available over the next 12 – 24 months 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. The change recognises network capacity utilisation and the costs attributable to dedicated assets such as street lighting circuits and poles.

Uncontrolled load 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 can 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 the following:

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

Power factor charges

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

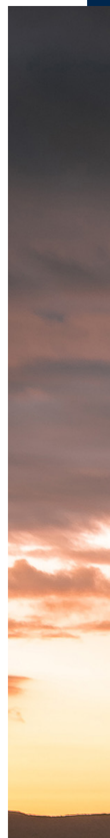
Distributed Generation (DG) price option

We have many DG installations connected to our network (approximately 1% of connections). Most are small sites (less than 10kW) that 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, potentially enabling us to do this. Currently, it is set at zero cents per kWh. The export price was 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. Avoided costs are recognised by not charging generators for injection into the network. Our approach is consistent with the incremental cost pricing principle under Part 6 of the Electricity Industry Participation Code. We do expect 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. Still, 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 December 2022, we are processing the application of one solar farm and are aware of another two developments looking to be connected to our 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 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 us, we will pay for the ongoing maintenance and operation of the assets. We may also make a customer contribution 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.

We 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, we believe that this will alleviate any potential cross-subsidy as fixed charges will exceed AC.

Our 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.

We have concluded from the publicly available analysis 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. As an example, residential customers considering connecting within 1km of Electra's existing network will likely find the network connection option to be cheaper than a stand-alone power system.

For larger connections, standalone costs may depend on the location of the 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. We have a relatively compact 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 (ToU)

On 1 April 2022, we adopted ToU pricing for our low and standard 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 peak, shoulder, and off-peak consumption will help us better reflect the economic costs associated with future capacity investments, as discussed in Section 4.

Connection capacity

Differences in connection capacity costs are reflected in the low, standard and industrial pricing category. Low and standard 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

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

Generation

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

Night only and night boost

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

Dedicated assets

Large Industrial customers 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 customers. The premium 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 we provide is access to the network. Distinctions are made in pricing for the type of end customer, ToU, capacity size, and asset specification.

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

- Connection capacity sizes are reflected in our low, standard, and Industrial customer groups and through capital contributions
- ToU services are provided 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 the 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 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 investing 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 currently relatively limited and is almost entirely Solar PV without batteries. Natural gas and LPG energy sources are also a partial substitute for electricity.

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

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

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

Our plan to increase fixed charges for domestic 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. Recognising 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 we 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 our prices. Residual cost should be recovered through non-distortionary pricing mechanisms following Principle B.

Non-distortionary pricing mechanisms included fixed prices, either charged on a daily or connection size basis. All customers contribute to residual network costs 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 low domestic users, who comprise most of our customer base. Our pricing strategy involves increasing the proportion of revenue from fixed charges consistent with the five-year phase-out of the LFC Regulations. Over time we will seek to align our fixed pricing structures to our residual costs.

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

i. Reflect the economic value of services

Our pricing reflects different network service offerings responsive to customers' needs. 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 the inefficient bypass of the existing infrastructure. We set our prices below SAC and above AC for each customer group. We would seek to do this for 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 the network can turn off the customer's hot water load to manage the network load, and
- We are open to non-standard arrangements that may allow for different service levels and security of supply standards (i.e. N-2 redundancy).

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

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

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

Our disclosures provide relevant information that 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 have led to a renewed focus on electricity line pricing. This increased focus has led us to undertake a strategic review of distribution line pricing arrangements to develop a long-term line pricing strategy.

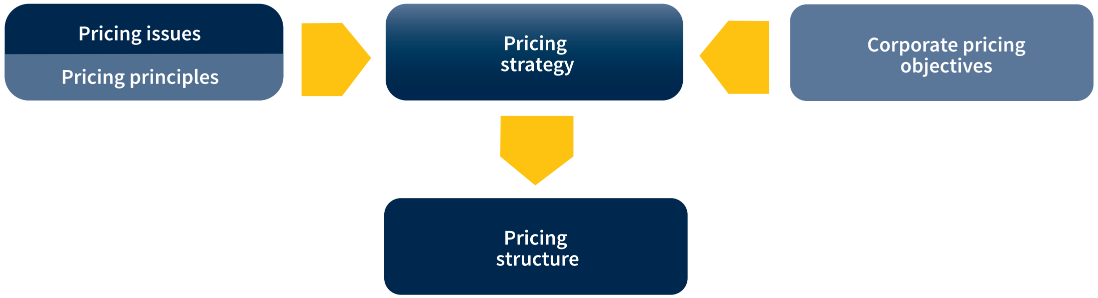


Figure 6: Drivers of the pricing strategy and pricing structure

Corporate pricing objectives

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

	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

Figure 7: Proposed corporate pricing objectives

Appendix Three:

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 we supply.

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

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