PRICING METHODOLOGY

2026

WAIPĀ NETWORKS

CLAUSE 2.9.1 OF SECTION 2.9

We, Jonathan Kay and Alex Ball, being directors of Waipā Networks Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

The following attached information of Waipā Networks Limited prepared for the purposes of clause 2.4.1 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

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

Jonathan Kay

Alex Ball

19 February 2026

WAIPĀ NETWORKS

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INTRODUCTION

Overview

Waipā Networks owns and operates the electricity network that delivers power to around 30,000 connections in Cambridge, Te Awamutu and the surrounding areas.

We're 100% owned by the Waipā Networks Trust on behalf of our connected customers. Our kaupapa is about delivering cost-effective, reliable energy services and solutions that meet the needs of our customers across a growing rohe.

Our district continues to grow, which means we need to plan and invest to ensure the network can meet future demand. Projects such as the Te Awamutu High Voltage Cable Upgrade and the new substation near Hautapu will support network capacity, safety and reliability over the long term. These projects require significant investment, alongside ongoing renewal and maintenance of our existing assets.

Our 2026/27 Pricing Methodology outlines the principles, objectives, and approach to allocating costs and setting our pricing strategy to address the energy needs of our customers in the communities we serve.

The methodology in recent years has focused on transitioning to more cost-reflective prices, including the staged introduction of mass market Time of Use Pricing which was completed in 2022.

2023 saw the beginning of a three-year transition towards a cost of supply model where prices better reflect the economic costs associated with different pricing groups. That transition was extended by a further year due to the adoption of Long Run Marginal Cost (LRMC) to inform the calculation of Peak kWh charges in 2025.

2026/27 sees the transition to a cost of supply model now complete. The 2026/27 methodology also makes changes to the structure of our Distributed Generation prices including the introduction of a negative price for injection that occurs during Peak times, also using a form of LRMC.

Our current (to 2027) 5-year Pricing Roadmap components remain largely unchanged. Some items have been pushed out a further year while the company focuses on pricing and connection process updates prompted by changes to Electricity Industry Participation Code. We have also replaced one component relating to exploring mass market options based on demand and capacity with a broad review of the structure of the non-Residential Price Categories. Our Pricing Roadmap is a "live" document and can be viewed on our website: waipanetworks.co.nz/partners/retailers/pricingroadmap/. The Roadmap timeline at publication of this document is found in Appendix II.

Our network – overview

Waipā Networks owns and operates the electricity distribution assets in Cambridge, Te Awamutu, and the surrounding rural areas. Our network covers parts of the Waikato, Waipā, Ōtorohanga, and Waitomo Districts.

Electricity supply into the network is via Transpower's Cambridge, Hautapu and Te Awamutu Grid Exit Points (GXPs). The Waipā network consists of 33 11kV feeders, about 4000 11kV/400V transformers, and associated 400V/230V reticulation servicing roughly 60,000 people in our community. We also own a 110kV transmission line from Transpower's Hangatiki GXP to the Te Awamutu GXP, which was commissioned in 2016 to improve the security of supply to Te Awamutu. In 2025 a new Hautapu GXP and associated 33kV zone substation was commissioned with approximately 11MW of existing Cambridge load shifted onto this supply point.

PRICING PRINCIPLES AND OBJECTIVES

Our pricing principles are used to define our pricing roadmap and determine annual network pricing.

1. Peak demand is one of our cost drivers. Our price structures and levels reflect this: we keep off-peak prices low, and our peak prices reflect the cost of adding peak capacity.
2. We collect the rest of our revenue through charges that reflect our fixed costs.
3. Our pricing also reflects service levels – connections that choose to have flexibility of load benefit from a lower price.
4. Each customer pricing group should at least cover the costs that it directly causes.
5. We recover shared costs in a way that leads to optimal network use and accounts for affordability. Preferably, each customer pricing group should contribute to shared costs.
6. We keep our pricing as simple as we can. We have separate pricing for customer groups or areas when:
   a. It is needed to ensure that each area covers its costs over the long term, and it would be in the best interests of our community.
   b. It means our prices better reflect our cost drivers and will lead to better outcomes for our consumers.
7. Our prices should enable our customers to make informed decisions on energy efficiency and use of alternative energy sources, where those options are more economic.
8. Our prices enable us to be financially sustainable, by enabling the company to cover costs and earn a reasonable return on capital so that we can reinvest back into our future network, while providing a reliable and safe service.

REGULATORY CONSIDERATIONS

Commerce Act

The Commerce Commission regulates electricity distribution services under the Commerce Act 1986. This document has been prepared to comply with Requirements 2.4.1 of the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012 (NZCC 22) issued 27 November 2024 and apply the 2019 Distribution pricing principles published by the Electricity Authority.

Low fixed charge (LFC)

The Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 required Electricity Distributors to offer residential consumers a price option at their primary place of residence, with a fixed price of no more than 15c per day (excluding GST), and where the sum of the annual fixed and volume charges on that price option equals any other price option available to those consumers when they use 8,000kWh per annum.

The LFC restrictions are being removed over a five-year period from 1 April 2022 allowing fixed daily prices to increase by $0.15 per day each year until 1 April 2027, when Low Fixed Charge Regulations are removed.

The 2026/27 pricing methodology continues to reflect the phasing out of these restrictions with a residential price of $0.90 per day, up from $0.75 per day in the previous period. This, combined with higher proportional increases in variable price rates, sees an average[1] residential price increase of 10% compared to the 6.16% target revenue increase across all groups.

Electricity Authority pricing principles and reform

The Electricity Authority publishes both pricing principles and practice notes. EDBs are required to either demonstrate alignment with the principles or explain the rationale for any inconsistency. A detailed commentary on our alignment with the principles is covered in Appendix III.

In 2022 and 2024 the Electricity Authority published open letters to EDBs regarding their focus areas and expectations around pricing reform. While some focus areas have been addressed in previous methodologies, those specifically addressed in this 2026/27 Pricing Methodology are:

- Increasing use of fixed charges to match the phase-out of low fixed charge regulations.
- Transitioning away from the recovery of fixed costs through use-based charges.
- Allocating revenue transparently.
- Assigning all ICPs to time varying tariffs with limited exceptions only.
- Setting Peak rates based on Long Run Marginal Cost.
- Reducing Off-Peak rates.

In addition to the above, the Authority has introduced several changes to the Code that take effect from 1 April 2026. These primarily relate to how EDBs price for new and upgraded connections including distributed generation (eg solar power). Whilst most of these changes are reflected in separately published documentation, this Pricing Methodology document details the introduction of a negative price for distributed generation[2] that occurs during Peak periods (Residential Advanced price category only).

[1] *An average consumer in the Waipā Networks area is considered as using approximately 8000 kWh per annum, of which 60% is at the Uncontrolled price and 40% at the Controlled price.*

[2] *Changes to the Code effective 1 April 2026 require distributors to introduce a negative distributed generation injection charge for any Price Category designed to target residential consumers, or small businesses (that have a network connection size up to 45kVA and that export up to 45kW of electricity back to the network at peak times).*

INDUSTRY COLLABORATION AND DEVELOPMENT

We believe that to ensure customer, regulatory and decarbonisation needs are met then collaboration and systems development across the electricity industry are essential.

EDB collaborative working groups

We are a member of the Electricity Networks Aotearoa (ENA), and have active representation on their Communications & Engagement, Distribution Pricing, Information Disclosure and Regulatory working groups. We are also a member of the Northern Energy Group (NEG) and their respective subcommittees. These groups allow the pooling of resources to help meet industry challenges, increase efficiency, and provide a more informed approach to regulatory matters.

WAIPĀ NETWORKS PRICING

Overview of methodology

Our pricing has traditionally focussed on providing a simple and low-cost offering to customers reflecting the relatively low-cost nature of its 11kV network. Significant demand growth, investment on the network including a new 33kV zone substation in Hautapu, changes to pricing regulations and how customers use energy have driven us to adopt more cost-reflective pricing.

The first step in our pricing transition was the staged introduction of mass market Time of Use (TOU) pricing which was a staged roll out to approximately 76% of ICPs completed in the 2022/23 pricing year. Exemptions were granted for customers without smart meters or remote communications, or to accommodate Retailer billing system issues. These restrictions were further tightened for 2025/26 with 93% of customers now on TOU based pricing as at December 2025.

Overview of changes for 2026/27

The 2026/27 Pricing Methodology continues the planned transition towards more cost-reflective pricing with key changes including:

- **Continued greater use of fixed charges:** We continue to transition to recovering a higher proportion of its costs through fixed charges. For 2026/27, we forecast approximately 32% of lines revenue to be recovered through fixed charges, up from 29% the previous year. Fixed daily prices for residential customers have increased to $0.90 per day, consistent with what is permitted under the phase out of the LFC regulations. Fixed charges for the General group have proportionally increased in line with Residential fixed charges. The increase in fixed charges is offset by proportionally lower variable charges.
- **Refinement to peak TOU charges:** Prior to 1 April 2025 the differential we charged between Peak and Shoulder TOU charges was previously based on an estimate of the Avoidable Cost. This approach was replaced with the Long Run Marginal Cost of upgrading the network for a particular customer group. This is consistent with the updated guidance provided by the Electricity Authority on how to set peak prices. For 2026 the LRMC inputs have been refreshed leading to further refinement of the Peak TOU charges.
- **Distributed generation prices & structure:** Prompted by Code changes, for residential connections we have introduced a negative price for distributed generation that occurs during Peak times. We have also adjusted the structure of our distributed generation prices, with these now expanded into Peak/Off Peak/Shoulder time periods for all standard pricing groups.

Target Distribution revenue increases by approximately 5% for 2026/27. When factoring in Transmission costs, overall Network prices have increased to recover a 6.16% increase in target revenue to $58.4M.

In the 2026/2027 year we have budgeted to pay $6.47M in customer discounts via two instalments.

How prices are set

Prices are set based on the following process:

1. Our target revenue for the year is calculated and compared to a simplified building block formula.
2. 2026/27 billing volumes are forecast using recent historical billing data projected forward for customer growth and usage behaviour.
3. Prices are set for non-standard customers based on established cost recovery formulae and are deducted from target revenues.
4. The cost components of target revenue are allocated to standard customer pricing groups using our cost of supply model to establish target cost allocations.
5. Fixed charges are set consistent with the LFC phase out plan and our strategy to transition to proportionally higher fixed charges. Fixed charge revenue is deducted from target revenue.
6. Variable prices are then calculated for standard customers. LRMC is used to set Peak prices and Off Peak prices are set using a notionally low rate. Other variable prices are then set to recoup the remaining target revenue across forecast billing volumes.

Target revenue

Target revenue is calculated to recover the following network costs, as shown in the table below.

For the 2026/27 year we have set a target revenue of $58.4m before customer discounts. This figure excludes any revenues received through connection charges which are treated separately.

SUMMARY OF 2026/27 TARGET REVENUE

$ 000	2026/27	2025/26
Transmission charges	14,738	13,427
Operating expenditure	24,471	23,157
Depreciation on assets	7,575	7,456
Tax allowance	2,817	3,193
Asset revaluations allowance	(4,443)	(5,507)
Customer discount	6,470	5,600
Return on investment (estimated)	6,828	9,061
Target revenue	**58,457**	**56,388**

Note: the above figures are forecasts and the actual figures will vary. 2025/26 Target Revenue components have been updated with the latest forecasts (where available) at the time of publication of this document and may differ to those published in the previous methodology.

Target Revenue 2026/27 represents a 3.67% increase on the current 2025/26 forecast, or a 6.16% increase on the Target Revenue originally set in the 2025 Pricing Methodology ($55.052M). The most significant increases in cost components for 2026/27 are transmission charges, operating expenditure and customer discounts.

Transmission charges

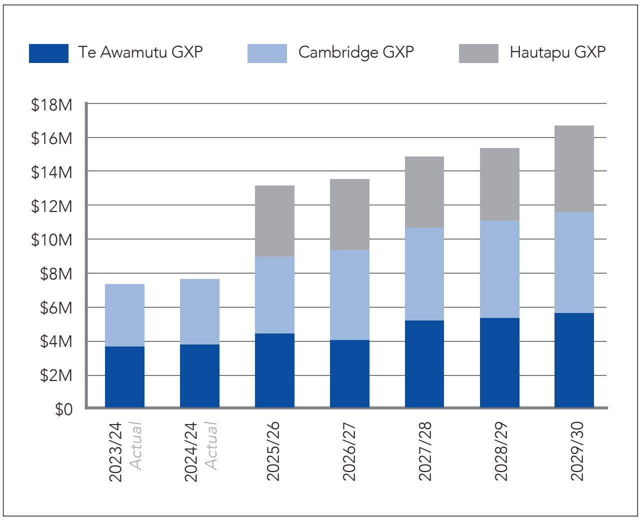
Transmission charges are charged to us by Transpower each year to connect to and use the national grid. Transmission charges are set based on Transpower's Transmission Pricing Methodology and include:

- Connection Charges – costs for GXP connection assets to the network and include those charged through Transpower Works Agreements (TWA) and Network Investment Contracts (NICs).
- Benefit-based Charges – a charge for use of core grid assets based on the benefit our customers receive.
- Residual Charges – a charge to recover Transpower's remaining costs, levied based on historical GXP Any Time Maximum Demand (AMD).

Guidance from both the Electricity Authority and the ENA suggests transmission charges should not drive changes in customer behaviour and should be allocated to prices based on simple broad-based allocators. Consistent with this, we allocate transmission charges to our standard customer groups based on simple kWh consumption (Benefit Based Charges and Residual Charges) and share of use of GXP capacity (for Connection Charges). For non-standard industrial customers, it has been possible to pass on transmission charges in a direct and transparent manner which provides efficient pricing signals to those customers.

The Transmission charges for 2026/27 are $14.7M, which is a 9.8% increase on the 2025 methodology forecast. This is significantly less than the 2025/26 increase of 74% which was a result of the commissioning of the new Hautapu GXP.

TRANSMISSION FORECASTS TO FY30($)



Transpower's transmission charges are regulated by the Commerce Commission according to 5-year "Regulatory Control Periods (RCPs)". The above graph shows a Transpower's charges to Waipā Networks in the final two years of RCP3 and the five-year forecasts under RCP4. For more information on Transpower's pricing please visit their website www.transpower.co.nz.

Maintenance of assets (opex)

The assets must be repaired and maintained in good working order to ensure a reliable supply of electricity to customers. An effective maintenance regime extends the life of assets.

Operations and overheads (opex)

These are the costs of operating the company: providing customer services, interfacing with electricity retailers, accounts and administration functions, and meeting extensive industry compliance requirements.

Other pass through costs (opex)

In addition to transmission charges, pass through costs include local body rates charged on the network, as well as the levies charged by the Commerce Commission and the Electricity Authority.

While the Commerce Commission allows transmission costs charged by Transpower to be passed through transparently these are treated independently (see above) to enable their charging structure to be passed through.

Depreciation of the regulatory asset base (RAB)

Depreciation recovers the costs of past asset investment in the network from the current users of those assets.

RAB revaluations

Revaluations of assets are deducted from target revenue to avoid over recovery as these are reflected in the depreciation and return on capital components.

Return on investment

The return on capital derived as the residual amount after the cost components described above are deducted from target revenue.

Tax

Tax payable on the return on investment.

Pricing groups

Customers are first classified according to the voltage at which they are supplied. The ICP numbers below are forecast for year-end 2026/27. (approximate number of ICPs shown in brackets):

- 11kV (15)
- Low voltage (29,892)

This is necessary as 11kV customers do not require the use of any low voltage distribution assets and should not be charged for them. We take supply from Transpower at 11kV and currently have no 33kV or higher voltage consumers. However, a 33kV zone substation was introduced in 2025 to meet network demand growth and this approach will be reviewed should a customer wish to connect at that voltage. Any such customer would be treated as non-standard.

11kV customers

11kV customers are further categorised as being:

- Standard (12), or
- Non-standard (3)

Standard 11kV customers share the 11kV distribution network with other 11kV and low voltage consumers.

Non-standard customers are those with dedicated assets from a Transpower GXP to their individual 11kV metering point.

Low voltage customers

Low voltage customers are further categorised as being either:

- Residential (24,516)
- General (5,180)
- 400V Capacity Contract (80)
- Non-metered (116).

Residential customers are classified as such where the primary use of the electrical supply is for domestic or residential purposes, as determined by the electricity retailer. These are typically indicated on the Registry as having ANZIC code '000000'. We reserve the right to challenge an electricity retailer's classification if we believe it is incorrect and backdate any charges in cases where a classification has been proven incorrect.

In rural areas residential customers may include individual ICPs required for domestic water pumps excluding stock or irrigation pumps.

Residential customers are required to be identified to comply with the Government requirement to offer small residential customers a daily fixed charge limited to no more than $0.90 (as part of the staged phasing out of the LFC restrictions).

General group customers are all other metered low voltage ICPs not defined as being Residential, except those who have C&I TOU metering (as indicated on the Registry) with a maximum demand of 70kVA or higher, who are classified as either 400V Contract or 11kV Contract (if supplied at 11kV). The criteria and structure of these three categories is longstanding despite recent updates to both the Waipā Networks' principles and regulatory environment. There may be an opportunity to improve the structure of these categories and we intend to review these prior to the 1 April 2027 pricing year. Our Pricing Roadmap (Appendix II) has been modified accordingly.

Non-metered supplies are typically telecommunication repeater cabinets and similar low wattage ICPs. These small installations are charged at a fixed daily rate.

Street lighting is generally non-metered and consumption is calculated based on hours of operation and lamp wattage. Streetlights are charged on their estimated kWh consumption.

Cost allocation

The cost of supply model allocates cost components to customer groups, excluding major customers, using forecasts of causal cost drivers, as follows:

Cost component	Cost driver (forecast for 2026/27)
Transmission	Coincident maximum demand and electricity volumes
Maintenance	ICPs and asset depreciation
Operations and overheads	Electricity volumes and ICPs
Pass through costs	Electricity volumes and ICPs
Asset related costs and returns	Asset value

Long run marginal cost (LRMC)

For 2025/26 we had set our peak prices with reference to an estimate of LRMC utilising an "average incremental cost". This has been developed by our pricing model provider, which looked at the incremental cost of growth and connections related expenditure on our network over the next 10 years. The capex information was primarily sourced from our Asset Management Plan, with some adjustment for project estimates that had yet to be factored in. Demand forecasts used were based on forecast ICP growth and an average demand profile. An LRMC estimate was calculated for each customer group to determine the contribution each group makes to future network growth expenditure. An adjustment factor was then applied to minimise price shock.

Ideally, the peak price would directly reflect the LRMC, as this is an estimate of the costs of upgrading network capacity that are driven by usage during peak periods. However, as the LFC regulations limit the revenue that can be earned through the fixed charge, the bulk of the revenue from residential connections needs to be recovered through usage charges. We set a low charge for usage in off-peak periods to reflect that the near zero-costs associated with off-peak usage of our network. The remainder of our revenue then needs to be recovered through peak and shoulder charges. To provide a signal of the cost that peak usage imposes relative to shoulder usage, we set prices so that the differential between peak and shoulder prices reflects the adjusted LRMC estimate.

This approach continues for 2026/27, with some further adjustments to the AMP inputs used for calculations and adjustment factors. Inputs used for the calculation are summarised in the following table, covering the 10-year period FY26-FY35:

	Residential	General	400V	11kV
ICP growth	3,514	–	25	4
Average kWh new customer	7,890	–	585,396	1,484,632
Average kW new customer	8	–	201	634
System growth	$ 13,716,839	–	$ 2,770,739	$ 1,050,577
Connection growth	$ 49,423,556	–	$9,395,672	$16,559,771
Less contributions	*($45,015,821)*	–	*($8,728,170)*	*($12,297,951)*

The LRMC model takes these inputs, along with allowances for associated opex, depreciation and tax, to calculate a present value dollar figure. This figure is then divided by the value of kWh consumption to give a LRMC differential figure of $/kWh. This process occurs for each of the price categories above which are then adjusted if deemed appropriate.

Adjustment factors have subsequently been applied as follows:

- The LRMC differential for the General group had been calculated as $0.00 due to 0 forecast growth. However, adopting this would mean equal rates for Shoulder and Peak and lose an important price signal. We have therefore retained the previous years' Shoulder/Peak differential.
- The LRMC differential for the 11kV group had been calculated significantly higher than other categories due to forecast demand increases and proportionally higher forecast capex for that group, however there is a level of uncertainty around ICP growth. It also likely that such a significant differential could encourage customers to reduce demand without material network benefit. We have therefore only increased the Shoulder/Peak differential slightly on the previous year.

The following table summarises the target and the per kWh differential applied between the shoulder and peak rates.

DIFFERENTIAL BETWEEN SHOULDER RATES AND PEAK RATES

Peak rate	2025/26 (LRMC adjusted)	2026/27 (LRMC)	2026/27 (LRMC adjusted)
Residential	$0.1000	$0.1556	$0.1556
General	$0.1000	$0.0000	$0.1000
400V contract	$0.0800	$0.0871	$0.0871
11kV contract	$0.0300	$0.3238	$0.0500

Despite these adjustments, the forecast revenue per price category is unaffected as the pricing model recalculates the other applicable rates to preserve total target revenue for each.

Non-standard customer capex is excluded from calculations as their pricing is calculated via a separate methodology.

Distributed generation negative price (negative distribution generation injection charge)

Changes to the Code effective 1 April 2026 require distributors to introduce a negative distributed generation injection charge for any Price Category designed to target residential or small business consumers. Waipā Networks does not have a category that is designed for small businesses as ICPs of that nature are assigned to the broader General category.

With regards to residential customers, we have two Price Categories – a Residential Advanced (RA) category which is the default, and a Residential (D) for ICPs that do not have a smart meter. Since 1 April 2017 Waipā Networks has required all residential ICPs with Distributed Generation to be assigned to the Residential Advanced (RA) category. As there are no smart meters with Residential (D) and no distributed generation customers in that category, no customers in that price category could make use of the negative price.

We also note that even if Waipā Networks permitted Distributed Generation ICPs to be assigned to the Residential (D) category, retailers would not be able to provide Peak distributed generation data due to the absence of a smart meter. In the interests of Code compliance however we deem that the negative price for the Residential Advanced (RA) category is also available to the Residential (D) category but have not indicated this in our Pricing Schedule to avoid confusion for customers.

Calculation method

The Code requires Distributors to use LRMC to calculate the negative price, with the option for the 2026/27 year to instead use the difference between consumption Peak and Off Peak rates. As Waipā Networks is already using LRMC for pricing we have chosen to use this for 2026/27 using the ENA / Link Economics model that was developed specifically for the calculation of distributed generation negative price.

This LRMC model is slightly different to the one used for the calculation of our Peak consumption charges. The consumption LRMC model focuses on setting prices for existing connections and price categories as a differential between Peak and Shoulder, with adjustments to other prices to meet target revenue per group. It uses a 10-year period, which includes the current and following year's capex.

The distributed generation negative price LRMC model instead determines a Peak rate independent of other prices. It uses an 8-year period, excluding capex in both the pricing year and prior year, as expenditure for these periods are typically already committed and therefore unable to be influenced by customer use of the network. The model also provides an LRMC based on capex universally rather than per price category. We note that this model is expected to be widely used by EDBs for the calculation of the negative price and so there is benefit in consistency of approach, particularly in the first year of implementation.

Inputs used for the calculation are summarised in the following table, covering the 8-year period FY28-FY35:

Cumulative incremental demand (MW)	24
System growth	$11,354,515
Connection growth	$58,520,000
Less contributions	*$51,305,857*

Although the inputs and time periods are different to the consumption LRMC model, the calculation method is the same. The LRMC model takes these inputs, along with allowances for associated opex, depreciation and tax, to calculate a present value $ figure. This figure is then divided by the present value of kWh consumption to give a LRMC differential figure of $/kWh.

Using these inputs and methodology, LRMC is calculated at $0.047 per kWh before the adjustment factor is applied (refer below).

Pricing regions

Waipā Networks has a single pricing region and we have therefore decided to apply a single negative price.

Peak time period

Although there is opportunity to apply a narrower time band for the negative peak price, we do not believe this is appropriate for the first year of the negative price given the lack of data regarding likely consumer behaviour. It could also be potentially confusing for customers to have different Peak time periods for consumption and injection. The applicable time periods are therefore 07:00 – 09:30 and 17:30-20:00.

Adjustment factor

The Code provides for an adjustment factor to be applied to the negative price. According to the Electricity Authority's updated Distribution Pricing: Practice Note Second Edition v2.2, "This should….reflect the specific risks and characteristics of injection with regard to transaction costs, consumer impacts, uptake incentives, and network stability."

To date, Waipā Networks has had a single 24h-hour injection price and therefore does not have data to indicate when it is likely customers will inject during peak times. As such, there are uncertainties around what impact the introduction of negative price will have on consumer behaviour and therefore network impact. Waipā Networks views this first year of introduction as an opportunity to gather data and refine the characteristics of the negative price for future years. The adjustment factor we have applied for this initial year is therefore focussed on transaction costs consisting of additional billing administration, analysis and modelling. We have applied a notional adjustment factor of 15% for 1 April 2026.

The distributed generation negative price applicable is therefore $0.047 less 15% = $0.04.

Prices for non-Peak distributed generation have been set at $0 to ensure these do not exceed incremental cost as required under the Code.

Distributed generation structure

Prior to 1 April 2026, Waipā Networks had a single kWh price for distributed generation. With the introduction of the new negative price for Peak aligned to our consumption Peak time periods, we have taken the opportunity to also add Off Peak and Shoulder prices also aligned to the consumption time periods. We have also created distributed generation prices for the 400V and 11kV price categories, which to date had none formally available.

Description	Existing price code	New price code 1 April 2026
Residential generation	WARG (24 hr)	WAG14 (Peak 07:00 – 9:30 and 17.30 – 20:00) WAG17 (Off Peak 22:00 – 07:00) WAG18 (Shoulder 09:30 – 17:30 and 20:00 – 22:00)
General generation	WAGG (24 hr)	WAG34 (Peak 07:00 – 9:30 and 17.30 – 20:00) WAG37 (Off Peak 22:00 – 07:00) WAG38 (Shoulder 09:30 – 17:30 and 20:00 – 22:00)
400V contract generation	WAGG (24 hr)	WAG54 (Peak 07:00 – 9:30 and 17.30 – 20:00) WAG57 (Off Peak 22:00 – 07:00) WAG58 (Shoulder 09:30 – 17:30 and 20:00 – 22:00)
11kV contract generation	N/A	WAG64 (Peak 07:00 – 9:30 and 17.30 – 20:00) WAG67 (Off Peak 22:00 – 07:00) WAG68 (Shoulder 09:30 – 17:30 and 20:00 – 22:00)

This structure change has been implemented effective 1 April 2026 following consultation with Retailers, who expressed support for the approach.

Off peak rates

In 2025 we set the off-peak tariff rate for all customer groups to $0.01 per kWh. This remains unchanged for 2026.

EDBs are assumed to have near zero costs associated with serving customers during the off-peak period (11pm – 7am for Waipā Networks). Practically, there are still costs of managing customers during the off-peak period, such as responding to faults.

The near zero rates recognises the Electricity Authority's recent guidance while still recognising some cost recovery and enabling data to be captured for that time period.

Although the rates are relatively low and off-peak usage is a smaller proportion of total kWh usage (approximately 20% for Residential, for example) the Pricing model adjusts remaining prices to ensure total revenue is not impacted.

Non-standard customers

The non-standard customer pricing methodology is used when ICPs have assets allocated for the sole or primary use of the customer from a Transpower GXP to the ICP's 11kV metering point. The charges consist of both Transmission and Distribution components and are reviewed annually.

Transmission component

In 2025 we modified the approach to allocating transmission charges to ensure non-standard customers connected to either Cambridge or the new Hautapu GXP contribute to both GXP transmission charges. The allocation was an improvement on the previous approach, but did not result in non-standard customers contributing to the shared costs associated with excess capacity at the two GXPs. For 2026 we have improved the cost allocation further to ensure non-standard customers contribute to the excess capacity costs for the GXP area they are connected to. There are two GXP areas – "Cambridge GXP Area" consisting of Cambridge and Hautapu GXPs, and "Te Awamutu GXP Area" consisting of the Te Awamutu GXP.

In allocating the proportion of charges we examined two approaches – the customer's Anytime Maximum Demand (AMD) to total GXP Area AMD, and the customer's connected capacity to total GXP Area connected capacity. AMD was ultimately chosen as this more closely aligns with how transmission charges are allocated to EDBs by Transpower.

Transmission charge components consist of the following:

- Connection Charges
- Transpower Works Agreements and similar
- Benefit Based Charges
- Residual Charges

Charges are allocated to each GXP area.

The AMD for each non-standard customer site is determined based on 12 months' data for the period September to August, which aligns to the time period Transpower uses to calculate the AMD for each GXP.

Costs assigned to each non-standard customer, for their applicable GXP area per charge component, are allocated as follows:

*(Customer AMD / GXP area AMD * GXP area transmission charge component)*

Distribution component

The approach to the distribution component of non-standard customer charges remains unchanged from previous years:

Asset charges

Charges for assets used solely by the customer are calculated as follows:

Regulatory asset base (RAB) equivalent value x WACC return rate

RAB "equivalent" value is referred to as dedicated assets for non-standard customers and are excluded from the RAB, however the method of calculating value is the same.

The WACC return rate used for 2026/27 is 6.44%, being the Commerce Commission notified DPP4 post-tax rate at the 65th percentile.

Depreciation

Depreciation costs for assets used solely by the customer are calculated as follows:

Replacement cost x depreciation rate

The standard Depreciation Rate for 2026/27 is 2.5%. Individual customers may have a different depreciation rate where the expected useful life is diminished due to future planned customer works or disconnection.

Replacement Cost is determined at the time of purchase of the asset, with annual inflation adjustment. We occasionally reset Replacement Cost for an asset if market rates become out of step with inflation adjustments. These costs were last updated in November 2023.

Maintenance

Maintenance charges are calculated as follows:

Replacement cost x maintenance rate

The maintenance rate used for 2026/27 is 2.2%.

Operations and network management

The Customer's share of Operations and Network Management costs for each site is calculated using ratios based on line length, asset replacement cost, and kWh sales. Asset data and values were updated in November 2025 while kWh sales were forecast using a 12-month dataset to 31 August 2025. Total Forecast Network Overhead Expenses are for 2026/27. Each of the components are calculated as follows:

(Customer line length / network line length) x (total forecast network overhead expenses / 3)

+

(Dedicated assets RAB equivalent value / network RAB value) x (total forecast network overhead expenses / 3)

+

(Site kWh sales / network kWh sales) x (total forecast network overhead expenses / 3)

=

Operations and network management charge

110kV Hangatiki Line

For Te Awamutu customers only, a charge for the 110kV Hangatiki line is applied and calculated as:

(Site Contracted Demand / GXP Area Capacity) x 110kV Line Total Charges

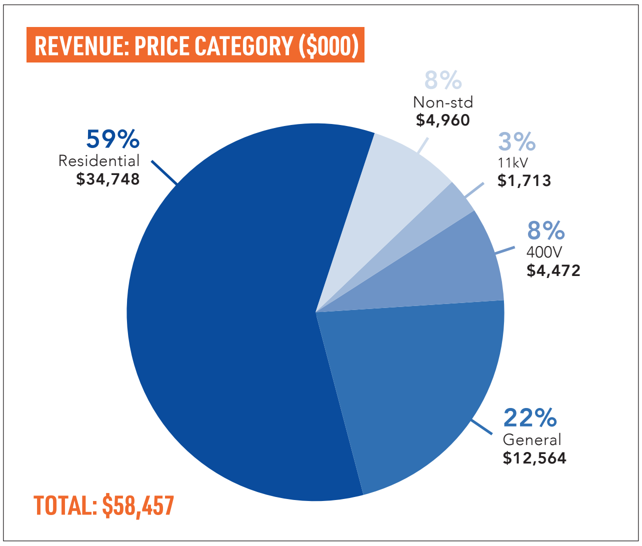
The 110kV Line Total Charges are calculated annually by Waipā Networks using the WACC return rate on RAB value plus maintenance and site costs.

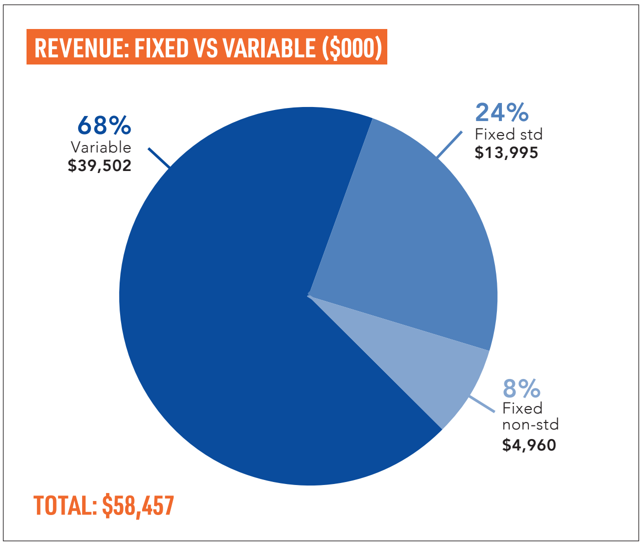
Revenue totals for large customers effective 1 April 2026 (aggregated) are as follows:

	2025/26	2026/27	% Change
Transmission	$2,092,753	$3,025,999	45%
Distribution	$1,878,946	$1,933,692	3%
Total	**$3,971,699**	**$4,959,691**	**25%**

Summary of pricing allocations

The following diagrams give a breakdown of revenue in terms of Price Category and Fixed/Variable.





Other pricing considerations

While not specifically factored into our cost of supply model, there are other considerations we make when setting our pricing strategy.

Congestion

The existing distribution network has a range of challenges, including:

- Regional supply constraints (eg. Transpower GXP capacity)
- Demand on four 11kV feeders that are near or at their capacity
- Rural feeders with limited backfeed capability, impacting reliability performance.

To address these constraints Waipā is performing the following activities:

- Upgrading low-capacity sections of the feeders and installing voltage management devices such as voltage regulators
- The new Hautapu GXP and Forrest Road substation (commissioned in FY26) has resolved the immediate Cambridge GXP constraint and laid the foundation for relieving feeder constraints. Now we are integrating the new Forrest Road substation into the Cambridge network
- Outlining a future proof network architecture for regional supply into Te Awamutu
- Defining the initial projects for the hybrid network and non-network architecture in Te Awamutu. This includes subtransmission circuits from Hautapu GXP to a zone substation near Waikeria Prison, and towards the end of the planning period, a new zone substation near Pirongia;
- New projects and programmes to improve the security in the Te Awamutu region (these are programmes that address both capacity and security)
- A continuation of our 11kV recloser installation programme
- A continuation of the switch automation programme.

Consultation

We consult on pricing to understand customer impacts, test comprehension of proposed changes, and ensure our approach remains fair, practical and transparent. Consultation occurs annually as part of our pricing update cycle, with additional targeted engagement when changes are material (for example, changes that significantly affect particular customer groups or require retailer system changes). We use the insights from consultation to refine our pricing roadmap, communications and supporting information, and we report back on what we heard and what changed as a result.

Customer

We use a mix of ongoing customer listening and targeted engagement to understand customer impacts, test how well customers understand pricing changes, and ensure our approach remains fair, practical and transparent. These insights inform our pricing roadmap, our annual pricing review, and how we communicate changes.

We consult with customers through:

- Annual customer survey
- Customer support, feedback and reporting
- Customer group meetings
- Social media
- Complaints resolution process
- Participation in sector engagement and pricing forums (including CEWG/DPWG and Northern Energy Group)

Annual customer survey (November 2025 results)

Our annual customer survey is a core customer listening input and helps us track trust, understanding and perceived value over time. The November 2025 survey saw a step-change in participation, with around 2,600 customers taking part (up from approximately 400 in previous years).

The survey is independently run and covers customer experience and communications, including overall satisfaction, reliability, image and reputation, value for money, and communications effectiveness. The November 2025 results are summarised in Table 1 and will be used to refine how we explain distribution charges, how we communicate any pricing changes, and what supporting information customers need to understand impacts.

For analysis, each customer/ICP is assigned to four customer groups:

- Grid Exit Point (Te Awamutu, Cambridge)
- Feeder type (Urban Te Awamutu, Rural Te Awamutu, Urban Cambridge, Rural Cambridge)
- Tariff type (Residential, General)

GXP and feeder type are treated as the key indicators, so we apply quotas to ensure the survey sample reflects the population mix. The latest survey results are summarised here:

ANNUAL CUSTOMER SURVEY RESULTS

Target	2025 results	2024 results
Overall satisfaction	64%	59%
Core Services	73%	78%
Image & reputation	58%	62%
Value for money	59%	52%
Communication	54%	49%
Enquiry Handling	75%	65%

The November 2025 survey shows improved overall satisfaction, value for money, communication, and enquiry handling, which supports customer understanding and acceptability of pricing change. The "Value for money" metric combines customers' views on delivery prices, the discount amount received, and how often the discount is applied. It is encouraging to see this result increase in 2025 compared to 2024, despite delivery price increases over the past year, underscoring the importance of clear, practical communication about pricing changes and likely bill impacts.

A new question in this year's survey examined the impact of retailer "free power" periods. The survey found **35%** of customers are on a plan that includes a free power period, and **66%** of those customers have changed their electricity use to take advantage of it

This result provides valuable insight into customer behaviour and the impact signalling can have on customer use of the network.

Customer support, feedback and reporting

We maintain a toll-free number and an online feedback form for customers to report operational or service issues. We record fault calls and resolutions in our database, and we analyse network faults and report them to the Board.

Customer groups – face to face meetings

We run a programme of face-to-face engagement to support wider discussion and gather feedback. This includes regular meetings with electricians to discuss our processes and services.

Social media

We maintain social media channels (Facebook and Instagram) and have steadily increased the volume of content we publish. Customers also use these channels to seek timely updates and provide feedback. We proactively publish information regarding activities of community interest and service announcements (such as outages of note), as well as monitoring them for customer feedback.

Complaints resolution process

We operate a Complaints Resolution Process in line with Utilities Disputes Ltd requirements. We assign a case manager to each complaint and keep complainants informed throughout the process.

We analyse complaints by complaint type and customer type. Pricing-related complaints typically make up less than 1% of complaints received and are often driven more by the retail price paid than Waipā Networks' distribution charges.

Communications and engagement working group (CEWG)

We participate in the Electricity Networks Association's Communications Engagement Working Group (CEWG) and Distribution Pricing Working Group (DPWG). Through this involvement, we contribute to sector-wide engagement and pricing practice and apply learnings to our network.

We are also members of the Northern Energy Group and its pricing and communications subcommittees.

Trust ownership

Waipā Networks is owned by a consumer trust elected by consumers every three years. We meet with the Trust at least twice a year and receive feedback on performance and the community's expectations regarding prices and service levels.

The Trust holds public Annual Meetings each year, giving consumers the opportunity to ask questions of both the Trust and the Company.

District councils

We hold discussions from time to time with the Waipā, Waikato and Ōtorohanga District Councils on their projects and overall supply quality.

Electricity retailers

Engagement with electricity retailers is key to developing practical and customer-centric pricing options, and to obtaining meaningful data to support network planning and future price development. We consulted comprehensively with retailers during our recent pricing structure changes.

RELATED POLICIES AND STANDARDS

This pricing methodology should not be viewed in isolation as there are other key policies that both feed into this methodology and receive input from it. All documents referenced below are available on our website www.waipanetworks.co.nz.

Network connection standards

These standards are referred to in the distribution agreements with electricity retailers who in turn reference them in their supply agreements with customers. They cover a wide range of topics that govern the use of our network such as technical standards, property access and power outages.

Distributed generation policy

Waipā Networks' Distributed Generation policy complies with Part 6 of the Code and covers connection costs, equipment standards, and approval processes.

Connections policy

This policy governs new and upgraded connections and includes how connection charges are calculated and cost recovered, including any capacity costing requirements.

Pioneer scheme policy

This details the Waipā Networks Pioneer Scheme, which governs connection charges paid by first-movers and any subsequent connections.

LOOKING FORWARD

Our Pricing Roadmap to 2027 is published on our website and in Appendix II.

In addition to this, our pricing strategy for the next 5 years is to:

- Continue to transition to a higher proportion of revenue recovered through fixed charges.
- Monitor and manage any potential customer price shock resulting from pricing reform.
- Use improved visibility of the LV network and associated data to provide more granular analysis of cost of supply.
- Further explore the case for locational-based pricing in light of increased investment in parts of the Network.

APPENDICES

Appendix I: Price and revenue tables

Residential	Forecast quanities	FY27 prices		Distribution	Transmission	Total		%
		Distribution ($/unit)	Transmission ($/unit)	Revenue ($)	Revenue ($)	Price ($/unit)	Revenue ($)	Price change
All inclusive	2,714,980	0.0902	0.0460	244,991	124,900	0.1362	369,891	-5%
Uncontrolled	7,646,615	0.1010	0.0504	772,258	385,727	0.1514	1,157,985	-5%
Night only	316,815	0.0147	0.0070	4,652	2,227	0.0217	6,879	-5%
Controlled	22,781,376	0.0237	0.0070	540,671	160,156	0.0307	700,827	-8%
Builders temporary	28,055	0.0607	0.0263	1,703	737	0.0870	2,440	-20%
Daily fixed price (default)	3,152	0.7228	0.1772	840,852	206,094	0.9000	1,046,946	20%
Peak	46,426,650	0.2568	0.0395	12,105,902	1,860,802	0.2963	13,966,704	18%
Off peak	35,407,828	0.0050	0.0050	179,769	179,769	0.0100	359,537	0%
Shoulder	48,790,121	0.1012	0.0395	5,011,983	1,955,330	0.1407	6,967,313	-7%
Peak (all inclusive)	7,837,888	0.2461	0.0347	1,952,695	274,998	0.2808	2,227,693	20%
Off peak (all inclusive)	4,759,968	0.0050	0.0050	24,092	24,092	0.0100	48,184	0%
Shoulder (all inclusive)	7,000,259	0.0905	0.0347	641,328	245,617	0.1252	886,945	-7%
Daily fixed price (TOU)	21,093	0.7228	0.1772	5,627,238	1,379,245	0.9000	7,006,482	20%
TOTAL RESIDENTIAL	**183,734,799**			**27,948,134**	**6,799,693**		**34,747,827**	

General	Forecast quanities	FY27 prices		Distribution	Transmission	Total		%
		Distribution ($/unit)	Transmission ($/unit)	Revenue ($)	Revenue ($)	Price ($/unit)	Revenue ($)	Price change
Uncontrolled	11,278,606	0.0483	0.0178	544,717	200,359	0.0661	745,076	-20%
Night only	91,640	0.0112	0.0042	1,027	387	0.0154	1,415	13%
Builders temporary	60,149	0.0557	0.0184	3,353	1,105	0.0741	4,458	-20%
Street lights	1,555,471	0.0437	0.0159	67,928	24,681	0.0596	92,610	-20%
Controlled	8,663,119	0.0114	0.0025	98,487	21,665	0.0139	120,152	-20%
Daily fixed price (default)	540	1.4457	0.3543	284,000	69,609	1.8000	353,609	20%
Unmetered daily charge	157	1.6063	0.3937	91,658	22,466	2.0000	114,124	25%
Peak	26,651,003	0.1484	0.0257	3,954,339	684,882	0.1741	4,639,222	-9%
Off peak	22,467,817	0.0050	0.0050	112,339	112,339	0.0100	224,678	0%
Shoulder	41,363,255	0.0484	0.0257	2,000,943	1,062,961	0.0741	3,063,903	-19%
Daily fixed price (TOU)	4,775	1.4457	0.3543	2,511,056	615,464	1.8000	3,126,520	20%
Unmetered daily charge	108	1.6063	0.3937	63,203	15,491	2.0000	78,694	25%
TOTAL GENERAL	**112,136,640**			**9,733,051**	**2,831,409**		**12,564,460**	

400V KVA capacity contracts	Forecast quanities	FY27 prices		Distribution	Transmission	Total		%
		Distribution ($/unit)	Transmission ($/unit)	Revenue ($)	Revenue ($)	Price ($/unit)	Revenue ($)	Price change
Minimum price for 70kVA	77	329.53	207.91	316,353	199,592	537.44	515,945	-31%
Each additional kVA of capacity	10,483	4.71	2.97	615,502	388,173	7.68	1,003,675	-31%
Peak	11,604,214	0.1184	0.0175	1,400,548	207,042	0.1359	1,607,590	-10%
Off peak	15,899,668	0.0050	0.0050	81,018	81,018	0.0100	162,036	0%
Shoulder	23,657,525	0.0313	0.0175	755,283	422,014	0.0488	1,177,297	-31%
Controlled	246,280	0.0176	0.0056	4,379	1,392	0.0232	5,771	-31%
TOTAL 400V CONTRACT	**51,418,248**			**3,173,082**	**1,299,231**		**4,472,314**	

11kv contract	Forecast quanities	FY27 prices		Distribution	Transmission	Total		%
		Distribution ($/unit)	Transmission ($/unit)	Revenue ($)	Revenue ($)	Price ($/unit)	Revenue ($)	Price change
Minimum price for 70kVA	11	225.03	321.42	29,704	42,313	546.45	72,017	-31%
Each additional kVA of capacity	6,379	3.21	4.59	246,079	350,300	7.80	596,380	-31%
Service charge	11	60.24	14.76	7,951	1,949	75.00	9,900	0%
Transformer rental	9,533	0.6178	–	70,676	–	0.6178	70,676	0%
Peak	5,172,908	0.0693	0.0242	361,943	126,393	0.0935	488,336	0%
Off peak	5,971,443	0.0050	0.0050	30,156	30,156	0.0100	60,312	0%
Shoulder	9,456,325	0.0193	0.0242	184,104	231,053	0.0435	415,157	-31%
TOTAL 11KV CONTRACT	**20,616,610**			**930,614**	**782,164**		**1,712,777**	

Appendix II: Pricing roadmap timeline

This table shows our current 2022-2027 Pricing Roadmap Timeline at the time of publication. For the full up to date Roadmap and commentary please visit https://waipanetworks.co.nz/partners/retailers/pricingroadmap/.

WAIPĀ NETWORKS PRICING ROADMAP

		2022	2023	2024	2025	2026	2027	Engagement Approach
1	Final stage of time of use implementation	✓						Completed
2	Align time of use time periods	✓						Completed
3	Adjust pricing in accordance with lfc removal					✓		Completed
4	Removal of cross-subsidies across price groups					✓		Completed
5	Streamline customer workflow and information – investigate and implement systems to support customer experience							Involve Customers and Community Groups in post implementation review and development.
6	Transition 400V and 11kv contract icps from amd-based charges to capacity							Liaise with retailers and customers to understand impacts and potential price shock.
7	Explore locational based pricing							Analyse cost of supply by location and develop pricing scenarios. Identify and understand Customer and Retailer impacts and preferences. Mediums: focus groups, meetings and surveys.
8	Review non-residential price category structures and criteria							

Initiate (identify and review) Develop (test, analyse, consult) Manage (roll out, implement)

Appendix III: Alignment with electricity authority pricing principles

Disclosure of pricing methodologies

(a) Prices are to signal the economic costs of service provision, including by:	Commentary
(i) being subsidy free (equal to or greater than avoidable costs, and less than or equal to standalone costs);	This principle asserts that prices are subsidy free and economically efficient for each consumer group where consumer lines charges fall between Avoidable Costs and Standalone Costs. LRMC has replaced the previous concept of Avoidable Cost as indicated in pricing reform guidance provided by the Electricity Authority in May 2024. Various features of our pricing approach support pricing within this subsidy range: • LRMC is embedded in our standard TOU peak time prices, as discussed above. • Non-standard customers pay at least their incremental costs of connecting to the network. Non-standard prices are typically set based on negotiation of a pricing approach for the provision of dedicated network assets or use of capacity. Any request for additional capacity or service capability is priced to recover at least the incremental costs of dedicated assets and upstream reinforcement. • Prices are calculated with reference to cost allocators that are reflective of the economic cost drivers of serving different consumer groups (eg demand and connections). On average, prices will therefore fall between LRMC and SAC. • Customer bills generally increase in-line with connection capacity and use of the network at peak times. This means charges will grow in line with LRMC and customer Standalone costs ensuring customers face the costs of supply fairly and transparently without subsidy. • New connection & existing connection upgrade costs are recovered through the Connections Policy. This sees the incremental connection costs recovered as capital contributions and the upstream connection costs through a Capacity Charge.
	Standalone costs Standalone costs represent the annualised cost that a group of consumers would incur to supply their energy needs from alternative energy sources. Practically this would be the cost of an "off-grid' energy solution. The Electricity Authority's pricing practice note provides guidance that Standalone Costs should be based on micro grid solutions where groups of consumers share energy resources. Using today's technology, off-grid micro-grid solutions might typically include a combination of Solar Photovoltaics (Solar PV), batteries, gas as a heating and cooking fuel, and diesel backup generation. The Ministry of Business Innovation and Enterprise Quarterly Survey of Electricity Prices November 2025 suggests average residential retail charges are 41.2 cents per kWh in the Waipā Networks distribution area, of which lines charges (including Transmission) comprise about 40% of the average retail bill. We understand that the per unit cost of a micro-grid scheme capable of serving a group of typical residential consumers is much higher than this average price. The cost of going off-grid for larger consumers is even higher, if not prohibitive, due to the desire to have high levels of security of supply to meet their energy needs.
	Avoidable costs The Electricity Authority's 2024 pricing distribution reform letter to distributors suggested that distributors should set peak rates based on a measure of LRMC, or the average incremental cost of growth. This signalled a departure from the previous use of Avoidable Cost, which is a similar concept albeit which looks at the cost an EDB would avoid by not having to build for growth. LRMC is the average incremental cost per KWh that a distributor faces in meeting future peak demand growth. If a customer is charged less than LRMC for their peak time usage, it would be beneficial to stop supplying that consumer group as revenue would not cover the distributor's future costs. Peak prices for each customer group should be set to be consistent with LRMC as signalled in the Electricity Authority's pricing reform letter from May 2024. Consistent with the ENA's pricing guidance we have calculated LRMC based on the average incremental cost approach (as outlined above) and applied this to the differential between our peak and shoulder rates. Average incremental costs are calculated as the present value of growth and connection related expenditure (as well as associated maintenance and tax) and is divided by the present value of peak time volumes to determine a kWh peak rate. This rate is added to our shoulder TOU rate to determine the peak time price.

(a)	Prices are to signal the economic costs of service provision, including by:	Commentary
(ii)	reflecting the impacts of network use on economic costs;	We have phased in new TOU pricing structures that better signal to consumers the economic costs of using network capacity. Approximately 93% of customers were on TOU pricing as at December 2025, and we have limited the exemption for being on TOU this pricing year to only customers that do not have smart meter infrastructure or communications. A key cost consideration for us is the significant recent growth in connections and peak demand on our network. This is putting strain on the network during peak times and in maintaining power quality to rural customers. The investment costs of installing additional GXP and feeder capacity to serve future peaks and improve power quality are significant. Since 2016 we have moved to pricing structures that provide sharper signals of the cost of providing peak capacity in the network and which encourage consumers to shift load to off-peak periods when the cost to serve is lower. This is a key reason for why we have made TOU pricing mandatory for all ICPs with advanced metering. Other drivers of economic costs include circuit length and voltage and connection capacity. We have decided not to distinguish consumers by circuit length or density (e.g. through rural/urban or GXP groupings) as our consumer research shows a preference to have no differentiation for rural connections. Our cost of supply model indicates the cost to serve the Te Awamutu and Cambridge Area GXPs are similar with Te Awamutu having 51% of the cost to supply compared to Cambridge's 49%. The Cambridge proportion has increased slightly on the previous year due to the commissioning of the Hautapu GXP. We will continue to monitor costs as plans progress to upgrade the Te Awamutu Area are progressed. If necessary, we may explore the need for regional or GXP based pricing to reflect any significant differences in the cost of supply. Our pricing structures have regard to the impact of network use on economic costs as follows: • **Use of peak network capacity** – Advanced Time of Use (TOU) pricing is available for the Residential, General and 400V pricing groups. Higher prices are applied at the peak time periods of 7am to 9:30am and 5:30pm to 8pm and lower prices during off-peak and shoulder time periods. This encourages efficient use of network capacity. Consumers are charged more for using assets during high cost peak periods or are rewarded for reducing or shifting their consumption to lower cost periods. Demand based prices are applied to 11kV connections and include an excess demand charge. Similar to TOU pricing, demand based prices reflect a consumer's maximum anytime use of capacity and therefore signal the cost of using additional capacity in the network. • **Connection voltage** – Pricing groups are distinguished by their connection voltage. Consumers either receive a low voltage (400V) or distribution (11 kVA) voltage service. Prices for 400V connections are allocated costs associated with providing low voltage assets. • **Connection capacity** – Differences in connection capacity costs are reflected in the 400V pricing category, through kVA capacity charges. Differences in connection capacity are also recognised through structuring pricing groups by typical connection sizes (e.g. residential, >70kVA). Looking forward, we plan to introduce capacity band pricing for 400V and 11 kV contract customers. • **Night only** – A night only 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 consumers to use network capacity during off-peak periods when the cost of network use is low. • **Load control** – Discounted pricing is applied to all low voltage connections that offer up interruptible hot water heating load. This signals network cost savings that are realised from shifting consumption away from network peaks and during security of supply events. • **Use of dedicated equipment** – Transformer rental charges are applied to 11 kVA connections to reflect the costs of providing dedicated transformers to these consumers. • **Non-standard customers** – Non-standard customers are those with dedicated assets connected to a Transpower GXP from their individual 11kV metering point. The three non-standard customers are priced to reflect the limited use of the distribution network. Transmission charges are also passed on directly. • **Streetlights** – Street lighting is generally non-metered and consumption is calculated based on hours of operation and lamp wattage. Street lights are charged based on estimated kWh consumption. The streetlight charges seek to directly recover the cost of streetlight specific assets. • **Generation** – The costs of providing export services are recognised through a generation export charge, and the TOU charges which better reflect the cost of providing capacity in the network for these customers.

(iii)	reflecting differences in network service provided to (or by) consumers; and	The key service provided is access to network capacity and connection services. Distinctions are made between different consumer service categories by connection capacity, asset use, quality of supply, and use of the network during peak periods as follows: • **Connection capacity** – Differences in service capacity are reflected in the pricing groups, the connection voltage, and explicitly in 400V pricing of kVA capacity. • **Time of use pricing** – Higher prices are charged at peak periods to reflect the cost of providing access services at periods of network congestion. • **Load control** – Consumers can choose an uninterrupted service (i.e. Uncontrolled) or a service where hot water load can be interrupted by the network for use in managing the network (Controlled). • **Non-standard customers** – Non-standard customers, primarily large connections connected to a GXP via an 11 kVA circuit, can negotiate specific services that are relevant to their circumstances. • **Non-metered** – The service that streetlights and other unmetered loads receive reflects their use of network assets, captured in a separate pricing category • **Use of dedicated equipment** – rental services associated with dedicated transformers are reflected in 11kV Contract pricing. Other asset and equipment requirements are reflected in industrial pricing and the network connections policy. • **Generation** – customers that require generation network-export services are charged separately through the generation export charges.
(iv)	encouraging efficient network alternatives	• Network pricing should encourage efficient investments in alternatives to the network provided. • 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 just over 1500 ICPs of which 85% are solar PV and a further 8% solar + battery storage. • For 2026 we have introduced a negative price for Peak distributed generation for our Residential Advanced group. This group makes up more than 90% of solar installations. As well as meeting obligations under recent Code changes, the introduction of the negative price will encourage consumers to consider battery storage alongside solar. Whereas solar alone does not offer any network benefits in terms of Peak reduction and in some cases can add to costs, battery storage has the potential help reduce network Peaks. • Also for 2026, we have introduced a distributed generation Peak/Off Peak/Shoulder tariff structure for all our standard pricing groups. Previously the distributed generation tariffs available were only a single 24 hour rate, meaning we did not have visibility of the times of day injection occurred. The new structure will provide valuable data and allow us to assess whether there is benefit in offering the negative price to categories other than Residential in future pricing. • We believe our charges are below the standalone cost of off-grid solar solutions. This discourages inefficient investments in off-grid solutions and disconnections from the network. It also allows us to compete with gas and LPG energy solutions on cost.
(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 through prices after deducting economic costs which have been recovered through service based charges in under Principle (a) above. For example, these costs might reflect general business administration or investments in existing base network assets that are largely unrelated to investments in capacity or network use. Regulatory guidance suggests residual costs should be recovered in a non-distortionary way, such as through a broad based fixed charge. That is, residual based prices should not encourage consumers to change their usage behaviour. Our current pricing structures are non-distortionary in the following ways: • Our Daily Fixed Price applied to Residential, General and Unmetered loads is consistent with non-distortionary cost recovery. We have increased residential fixed charges in line with the phase out to the Low Fixed Charge regulations, with proportional increases to other customer group fixed charges. • Our off-peak and shoulder TOU prices and Night charges also recognise the residual costs of using the network during non-peak periods. Together these residual charges reflect only 43% of our total target revenue.

(c) Prices should be responsive to the requirements and circumstances of end users by allowing negotiation to:	Commentary
(i) reflect the economic value of services; and	We are open to negotiating non-standard arrangements for very large connections that are at risk of bypassing the network or which may require different levels of service. Non-standard pricing more accurately reflects the avoided costs of providing services to these large consumers. We allow larger connections to specify their connection capacity requirements through capacity prices and the provision of dedicated transformers. Other specialist assets are addressed through our Connections Policy.
(ii) enable price/quality trade-offs.	Price/quality trade-offs are inherent in the pricing options. The trade-off relates to the key service offered which is unlimited and uninterrupted access to the network. Consumers should be able to make price/quality trade-offs based on the level of service they are willing to accept. The level of service reflects availability of supply, reliability and connection capacity. This is recognised as follows: • **TOU pricing.** Consumers receive more cost-effective access to the network by consuming during off-peak and shoulder periods. • **Uncontrolled pricing plans** have higher prices recognising the benefits of uninterrupted supply. Controlled pricing plans have lower prices recognising consumers' acceptance of lower service quality through interrupted load. • 400V and 11kV customers can select the **capacity of service** they require through the kVA demand pricing. In future we are planning to shift from demand-based prices to capacity band based prices for these groups. • We allow for **non-standard connections** or asset costs to be recovered through capital contributions. This allows consumers the opportunity to select their service quality based on their willingness to pay. Non-standard consumer connections are able to negotiate the level of service they require which is reflected in the contract price.
(d) Development of prices should be transparent and have regard to transaction costs, consumer impacts, and uptake incentives.	• The pricing methodology and annual price changes are uploaded on our website each year. These disclosure documents comply with the regulatory standards so that consumers and retailers have sufficient information about prices and to understand how prices are determined. • Pricing structures are limited to fixed daily and TOU consumption tariffs for all but a small number of exempt and large consumers. • We have closed legacy pricing structures and plan to transition these out over time, which will simplify pricing structures. • We have sought to reduce retailer transaction costs by developing pricing to reflect industry standard terminology, consumer profiles and connection characteristics, where possible. TOU pricing, has been developed to align with typical daily load profiles and the time periods of neighbouring EDBs.

Appendix IV: Glossary

AMD	Anytime Maximum Demand	The maximum demand (load) placed on the network by a customer or consumer group.
AMI	Advanced Metering Infrastructure	Also known as smart meters. These are capable of recording how much power is used in half-hour time periods over the course of a day.
Code	Electricity Industry Participation Code	Sets out the duties and responsibilities for all electricity industry participants. It also sets out the responsibilities of the electricity authority.
CRM	Customer Relationship Management system	The software that waipā networks uses or will use to management its engagement with customers.
C&I TOU	Commercial & Industrial Time of Use Metering	For the purposes of waipā networks pricing, this is the field on the registry which waipā networks uses as part of the criteria for certain price categories.
DER	Distributed Energy Resources	Includes small scale generation such as solar, batteries, electric vehicles connected to smart two-way chargers, and other new smart technologies.
EA	Electricity Authority	The government agency responsible for the governance and regulation of the electricity industry.
EDB	Electricity Distribution Business	Waipā networks is an edb.
ENA	Electricity Networks Aotearoa	The organisation that represents and advocates for New Zealand edbs.
ERANZ	Electricity Retailers Association of New Zealand	The organisation that represents and advocates for New Zealand electricity retailers.
GXP	Grid Exit Point	The place where the edb's network is connected to transpower's national grid.
ICP	Installation Control Point	The customers point of connection to waipā's network.
Kaupapa	Purpose	The values, principles and plans waipā networks uses as a foundation for what we do.
kV	Kilo-Volt = 1,000 Volts	A measure of electrical pressure or voltage.
kVA	Kilo-Volt Ampere	A measure of power for electrical load and is used to rate transformers and other electrical equipment. It is also used to calculate prices for capacity or demand-based price plan.
kW	Kilo-Watt	A measure of electrical power.
kWh	Kilo-Watt hour	A measure of electricity consumption. Equals one kilowatt being consumed for one hour.
LFC	Low Fixed Charge	The regulated maximum fixed daily price that can be applied to residential low electricity users.
Rohe	District or Region	The waipā area boundaries.
RC	Replacement Cost	This is the current value of waipā networks' distribution assets.
RAB	Regulated Asset Base	This is the value of waipā networks' distribution assets.
Registry	Electricity ICP Registry	The electricity authority's central database of all icps.
SAC	Stand alone Costs	The annualised cost that a group of consumers would incur to supply their energy needs from alternative energy sources.
SCADA	System Control and Data Acquisition	The type of computer software waipā networks uses to monitor and control its' electricity network.
TOU	Time of Use	A method where kwh usage is priced according to the time of day it is used.
TPM	Transmission Pricing Methodology	The approach taken by transpower when recovering costs from those connected to its grid.
TWA	Transpower Works Agreement	The costs related to building the new transpower gxp at hautapu.
V	Volt	A measure of electrical pressure or voltage.
WACC	Weighted Average Cost of Capital	The average rate that a business pays to finance its assets. We have used the commerce commission notified dpp4 post-tax rate at the 65th percentile, which for 2025/26 is 6.44%.

THANK YOU!

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