ELECTRICITY DISTRIBUTION SERVICES PRICING METHODOLOGY

From 1 April 2026

Pursuant to: The Electricity Distribution Information Disclosure (amendments related to IM Review 2023) Amendment Determination 2024 (Consolidated 27 November 2024)

Contents

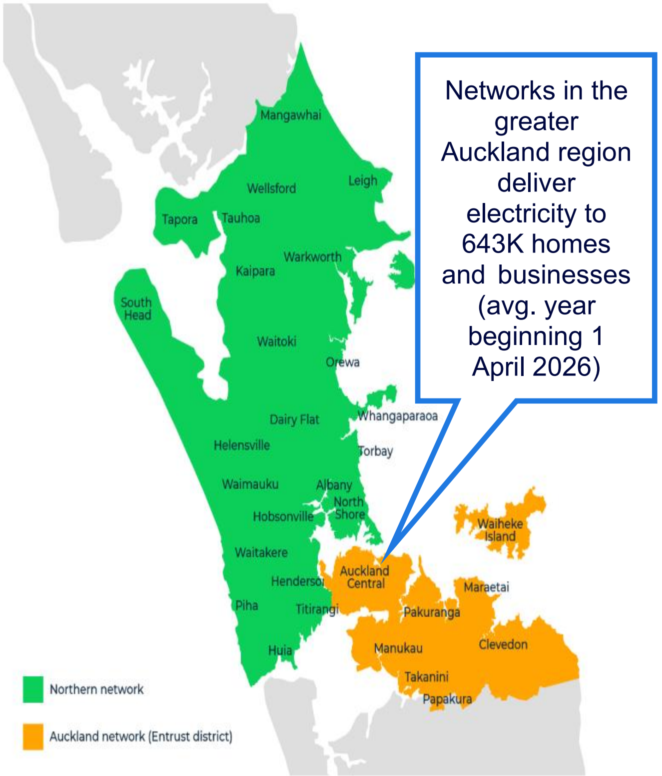
Contents

INTRODUCTION & CONTEXT

INTRODUCTION

Vector Limited ("Vector", "our", "we", or "us") recovers the cost of owning and operating our electricity distribution networks (Network) through a combination of standard (published), non-standard prices for electricity distribution services, and connection charges for new connections and upgrades. We are regulated by the Commerce Commission (Commission) and are required to publish our pricing methodology for electricity distribution services (Pricing Methodology).

Figure 1: Our electricity distribution



In this document, we refer to consumers and customers, however contractual requirements mean that our prices largely apply to Installation control point numbers (ICP), as we bill electricity retailers on an ICP basis. Electricity retailers have discretion as to whether they pass our charges on to end users. Therefore, the consumer impacts described in this document will only apply if our prices are passed through by electricity retailers.

This document explains how our Pricing Methodology meets the requirements of the Information Disclosure (amendments related to IM review 2023) Amendment Determination 2024 (ID)[1]. It describes:

1. Consumer groups;
2. The price categories and components within each consumer group;
3. Reasons for price changes;
4. How we comply with pricing principles;
5. How prices are set; and
6. The Cost of Service Model (COSM) allocation of target revenue to consumer groups.

The ID requires price change commentary relating to a pricing strategy[2]. We do not currently have a pricing strategy as defined in the ID. We do however have a publicly available electricity pricing roadmap[3]. The roadmap sets out how we are evolving our prices to help deliver Vector's Symphony Strategy and deliver better outcomes for consumers. As well, the roadmap explains how we are designing our prices in response to

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[1] Electricity Distribution Information Disclosure (amendments related to IM Review 2023) Amendment Determination 2024 (consolidated 27 November 2024), available at https://comcom.govt.nz/__data/assets/pdf_file/0026/363365/Electricity-Distribution-Information-Disclosure-amendments-related-to-IM-Review-2023-Amendment-Determination-2024-red-lined-version-27-November-2024.pdf

[2] A pricing strategy is a decision made by the Directors on the electricity distribution business' plans or strategy to amend or develop prices in the future, and recorded in writing

[3] Available at https://www.vector.co.nz/personal/electricity/about-our-network/pricing under the heading "consumer-led pricing design"

pricing guidance issued by the Electricity Authority. The roadmap is updated at least annually in April.

As noted above connection charges impact the way we set prices. This document does not contain our connection pricing policy[4] as it is disclosed in a separate document.

Key Pricing Considerations:

Prices are set to earn the level of revenue we are permitted to under the Default Price Path (DPP) set out in the DPP Determination[5]. The Commission determines that the allowable revenue an electricity distributor business (EDB) can earn over the five-year period from 2026 to 2030.

When setting prices, we take into account (amongst other things) - historical price structures, minimising rate shock, pricing principles[6] when appropriate, ensuring that prices to individual consumer groups reflect their allocation of costs, pricing guidance issued by the Electricity Authority and feedback from consultation processes with Entrust and retailers.

For the year commencing 1 April 2025 the Commission sets the forecast net allowable revenue a distributor can earn. On top of forecast net allowable revenue, the DPP allows prices to also change to reflect pass-through costs (e.g. Transpower transmission charges, council rates and statutory levies) and recoverable costs (e.g. IRIS, wash-up drawdown amount and quality incentive allowance).

Pricing under the forecast allowable revenue is permitted, noting that any undercharging below the undercharging limit set by the Commission is not recoverable. From the second assessment period onwards, we must comply with the revenue smoothing limit (RSL), which limits year-on-year changes in the forecast net allowable revenue and recoverable costs under the DPP. Any revenue foregone in the period due to pricing below the forecast allowable revenue and above the undercharging limit can be recovered in future periods. The undercharging recovered in future periods is adjusted for time value.

Not all consumers will see the weighted average price change when prices change, some will see more and some less depending on their consumption profile. Our calculation of the weighted average price change assumes our price changes are passed on by electricity retailers as we typically bill electricity retailers not end-use consumers.

PRICING APPROACH CONTEXT

The future is unpredictable. There is uncertainty around existing regulatory frameworks and new business models are ever evolving in response

[4] Available at https://www.vector.co.nz/about-us/regulatory/disclosures-electricity/capital-contributions

[5] Default Price-Quality Path Determination 2025 available https://comcom.govt.nz/__data/assets/pdf_file/0027/363276/5BFINAL5D-Electricity-Distribution-Services-Default-Price-Quality-Path-Determination-2025-5B20245D-20-November-2024.pdf

[6] Available at https://www.ea.govt.nz/industry/distribution/distribution-pricing/

to new consumer demands, new technologies and decarbonisation. We have taken the strategic decision to embrace these changes. We see this new environment as an opportunity to design and redesign our pricing in response to an evolving market. The regulatory framework plays a major part in our response this year.

DERIVING OUR PRICES

CONSUMER GROUPS

We determine consumer groups based on how customers use the network and the nature of the network service they receive. Consumer groups are determined at a relatively high level, the main reasons for this are below:

- There is a high degree of network meshing and interconnection of consumers;
- End consumers are not generally geographically segmented in their use of different network assets, for example, there are very few purely “industrial zones” or “residential zones”; and
- There is a mix of consumers, including a large number of consumers with relatively low individual consumption, and vice versa.

Our standard consumer groups are based on a measure of capacity connection and supply connection point type as shown in Table 1. Consumer groups are mutually exclusive so a consumer can only be in one group.

Table 1: Consumer groups

Consumer group	Subgroup	Capacity connection	Supply connection
Mass market	Residential & General	Small ≤ 69kVA	Low voltage network
Unmetered	General	Small ≤ 1kVA	Low voltage network
Low voltage	Commercial	Large ≥ 69kVA	Low voltage network
Transformer	Commercial	Large ≥ 69kVA	Vector owned transformer(s) which supplies the consumer’s low voltage network
High voltage	Commercial	Large ≥ 69kVA	High voltage (11kV or higher) network
Zone substation	Commercial	Large ≥ 69kVA	Directly from a Vector zone substation
Sub-transmission	Commercial	Large ≥ 69kVA	Sub-transmission (11kV or higher) network
Non-standard		Various	Various

Consumers on non-standard contracts which have met certain eligibility criteria, as outlined on page 35 are included in a separate consumer group.

The mass market consumer group is split into two subgroups: residential and general with a key difference being that the Low User Regulations [7] apply only to the residential subgroup.

The unmetered consumer group is also in the general subgroup. The low voltage, transformer, high voltage, zone substation and sub-transmission consumer groups are collectively referred to as commercial.

There is no change in consumer groups in pricing year 2027 (PY27).

[7] The Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 (the Low User Regulations) available at https://www.legislation.govt.nz/regulation/public/2004/0272/latest/dlm283614.html

PRICE CATEGORIES

Table 2 sets out the price categories for consumers on our Auckland network (codes beginning with A) and our Northern network (codes beginning with W). There is no change in price categories in PY27.

Table 2 Price categories

Consumer group	Categories	Auckland codes	Northern codes	Description including key eligibility criteria if applicable
Mass Market	Residential - time of use (TOU) - uncontrolled	ARHLU ARHSU	WRHLU WRHSU	Residential consumers without controllable load, hot water (ripple or pilot wire)
	Residential - TOU - controlled	ARHLC ARHSC	WRHLC WRHSC	Residential consumers with controllable hot water load (ripple or pilot wire)
	Residential - TOU - Distributed energy resource (DER)	ARHLD ARHSD	WRHLD WRHSD	For customers with load that can be connected to or respond to our distributed energy resource management system
	Residential - Anytime (exemption) - uncontrolled	ARNLU ARNSU	WRNLU WRNSU	Residential consumers with a Vector provided exemption from TOU price categories, and without controllable load
	Residential - Anytime (exemption) - controlled	ARNLC ARNSC	WRNCL WRNSC	Residential consumers with a Vector provided exemption from TOU price categories, and with controllable load
	General – TOU	ABSH ABSHD	WBSH WBSHD	Non-residential < 69kVA consumers
	General – Anytime (exemption)	ABSN	WBSN	Non-residential < 69kVA consumers with a Vector provided exemption from TOU price categories
Unmetered	General – unmetered	ABSU	WBSU	Unmetered < 1kVA capacity connections, mostly street lighting

PRICE CATEGORIES (continued)

Table 2 Price categories

Consumer group	Categories	Auckland codes	Northern codes	Description including key eligibility criteria if applicable
Low voltage (LV)	LV – TOU	ALVT ALVTS ALVTD	WLVH WLVHS WLVHD	Main category for LV consumers, requires TOU metering
	LV – non-TOU	ALVN	WLVN	For smaller LV consumers (< 345kVA) who do not have TOU metering
Transformer (TX)	TX – TOU	ATXT ATXTS ATXTD	WTXH WTXHS WTXHD	Main category for TX consumers, requires TOU metering
	TX – non-TOU	ATXN	WTXN	For smaller TX consumers (< 345kVA) who do not have TOU metering
High voltage (HV)	HV – TOU	AHVT AHVTS AHVTD	WHVH WHVHS WHVHD	Main category for HV consumers, requires TOU metering
	HV – non-TOU	AHVN	WHVN	For smaller HV consumers (< 345kVA) who do not have TOU metering
Zone substation (ZS)	ZS – TOU	AZST AZSTS AZSTD	WZSH WZSHS WZSHD	Category for ZS consumers, requires TOU metering
Sub-transmission (ST)	ST – TOU	ASTT ASTTS ASTTD	WSTH WSTHS WSTHD	Category for ST consumers, requires TOU metering

PRICE COMPONENTS

We have a range of price components that apply to different price categories depending on the characteristics of a particular category and the availability of metering data. Table 3 describes the various price components that we have. A peak volume price is applicable for the period we define as peak, reflecting network constraints (see Figure 2 Peak and off-peak times and Table 4 Days and times for peak and off-peak periods)

Table 3: Price components

Type	Component	Code	Units	Description
Fixed	Daily	FIXD	$/day	Daily price applied to the number of days each consumer's point of connection (or fitting for unmetered connections) is energised
	Capacity	CAPY	$/kVA/day	Daily price applied to the installed capacity (or nominated capacity for HV, ZS and ST) of each ICP
Variable	Volume	AICO, 24UC, OFPK, PEAK	$/kWh	Volume price applies to all electricity distributed to each ICP. Controlled volume (AICO), uncontrolled volume (24UC), off peak volume (OFPK), peak volume (PEAK)
	Demand	DAMD	$/kVA/day	Daily price applied to the average of the consumer's ten highest kVA demands between 8am and 8pm on weekdays each month
	Excess demand	DEXA	$/kVA/day	Daily price applied when the anytime maximum demand is greater than the nominated capacity and is applied to the difference between the anytime maximum kVA demand and the nominated capacity
	Power factor	PWRF	$/kVAr/day	Daily price determined each month where a consumer's power factor is less than 0.95 lagging. The kVAr amount is calculated as twice the largest difference between the recorded kVArh in any one half-hour period and the kWh demand recorded in the same period divided by three
	Injection	IJOP, IJPK, INJT	$/kWh	Volume injection price applies to all electricity injected into the network by each consumer. Injection off-peak (IJOP), injection peak (IJPK), Injection anytime (INJT)

Each price component can be designed to recover distribution costs, pass-through and recoverable costs. Transmission costs are not part of the price components as we have adopted a GXP pricing approach since 1 April 2023 with further explanation on page 20.

MASS MARKET AND UNMETERED PRICE CATEGORIES

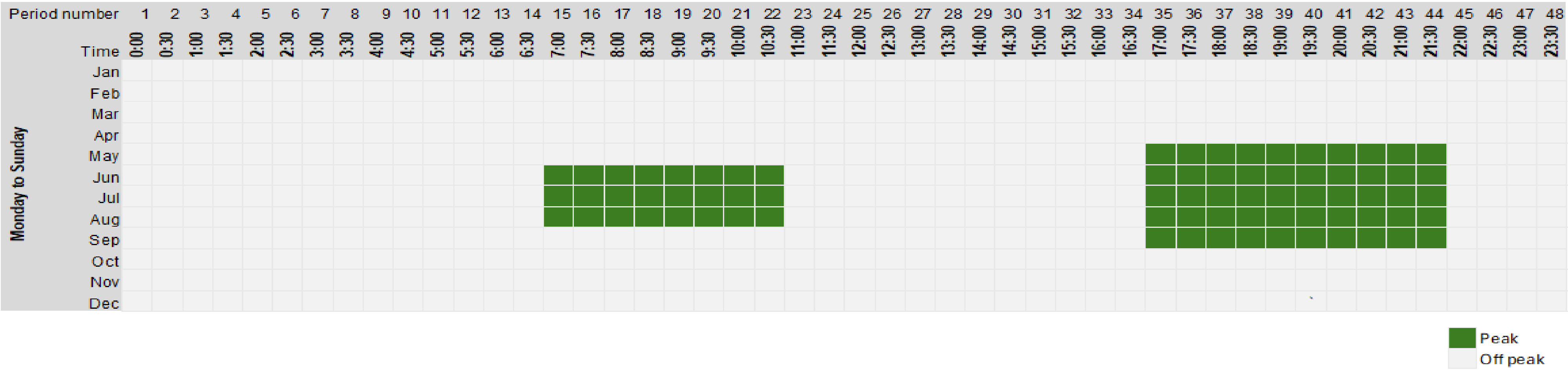
Our PY27 mass market price categories continue to be split into two-part time of use and flat volumetric (non-time of use).

1. Two-part time of use - daily fixed price with varying volumetric prices depending on usage period, as shown in Table 4 Days and times for peak and off-peak periods and also illustrated in Figure 2 Peak and off-peak times.

Table 4 Days and times for peak and off-peak periods

Period type	Days	Times
Peak	Monday to Sunday (including public holidays) in months June to August, inclusive	07:00 – 11:00
	Monday to Sunday (including public holidays) in months May to September, inclusive	17:00 – 22:00
Off-peak	Monday to Sunday (including public holidays) in months May and September	22:00 – 17:00
	Monday to Sunday (including public holidays) in months June to August, inclusive	22:00 – 07:00 11:00 – 17:00
	Monday to Sunday (including public holidays) in months October to April, inclusive	All times

Figure 2 Peak and off-peak times



2. Flat volumetric pricing - daily fixed price and any anytime volumetric price, which is only available as an exemption. We apply peak[8] and off-peak pricing to TOU metered ICPs unless an exemption is arranged with us. The peak price is only applicable in peaking months to better focus the price signal to peak loads, and excludes months where constraints are presently not a concern.

[8] TOU LRMC conversion: Where LRMC is used to inform TOU peak pricing, the annual LRMC signal (in $/kW-year) is converted into a peak volumetric signal (in $/kWh) by dividing by the number of hours in the defined peak periods.

Our residential price categories include controlled, uncontrolled and DER price categories. The controlled price categories are designed to reward customers (via retailers) where an ICP has controllable hot water load connected to Vector's load control system, supporting reductions in load during peak periods.

The DER price categories are designed to support future flexibility and load management capability by incentivising ICPs with devices that can be remotely managed off or down by retailers (for example, hot water cylinders, EV chargers and pool pumps) and are available to eligible mass market ICPs with a communicating TOU meter.

These price categories provide incentives to manage and shift load during peak times, which can help reduce peak demand pressure, and over time, avoid or defer network investment. The DER price category is also made available for general TOU metered ICPs.

We have a two-part charge for unmetered price categories with fixed and volumetric prices. The fixed price is the number of days each point of connection of fitting is energised. Unmetered ICP volumes are determined by Vector based on load profiles and fitting input wattages.

Table 5 shows the price components applicable to the price categories for the mass market and unmetered consumer groups.

- The pass-through cost recovery is only through the daily fixed charge. The transmission cost recovery is not included as we have adopted a GXP Pricing Methodology since 1 April 2023 to recover transmission costs.

Table 5: Price components applicable to mass market and unmetered price categories from 1 April 2025[9]

Consumer group and sub group		Price category type	Price category description	Price category codes	Daily	Volume anytime	Volume off-peak	Volume winter peak	Volume injection
					-FIXD	-24UC / -AICO	-OFPK	-PEAK	-INJT
					$/day or $/day/fitting	$/kWh			
Mass market	Residential	TOU	Low user	ARHLC, ARHLD, ARHLU, WRHLC, WRHLD, WRHLU	✓ D P		✓ D	✓ D	✓
			Standard user	ARHSC. ARHSD, ARHSU, WRHSC, WRHSD, WRHSU	✓ D P		✓ D	✓ D	✓
		Anytime (exemption)	Low user	ARNLC, ARNLU, WRNLC, WRNLU	✓ D P	✓ D			✓
			Standard user	ARNSC, ARNSU, WRNSC, WRNSU	✓ D P	✓ D			✓
	General	TOU	General	ABSH, ABSHD, WBSH, WBSHD	✓ D P		✓ D	✓ D	✓
		Anytime (exemption)	General	ABSN, WBSN	✓ D P	✓ D			✓
Unmetered		Unmetered	Unmetered	ABSU, WBSU	✓ D P	✓ D			✓

[9] D is distribution cost recovery only and D P has both distribution and a pass-through cost recovery. There are no transmission cost recovery included in the price categories.

COMMERCIAL PRICE CATEGORIES

Our price structure for commercial price categories is largely historical. There were (and, to a lesser extent, still are) a variety of price categories with different combinations of price components and price levels, due largely to pricing differences that existed prior to both networks being owned by us.

All commercial price categories consist of daily fixed, anytime volume, capacity, power factor and injection prices. TOU price categories (which have been mandatory from 1 April 2022 for all new commercial consumers, and existing consumers with the metering capability) also have demand and excess demand (for high voltage and above consumers) prices.

Table 6 shows the price components applicable to the price categories for the commercial consumer groups.

Table 6: Price components applicable to commercial price categories[10]

Consumer group	Price category	Price category codes	Daily -FIXD $/day	Capacity -CAPY $/kVA/day	Volume - anytime -24UC $/kWh	Demand -DAMD $/kVA/day	Excess demand -DEXA $/kVA/day	Power factor -PWRF $/kVAr /day	Volume - injection -INJT $/kWh
Low voltage	TOU	ALVT, WLVH ALVTS, WLVHS ALVTD, WLVHD	✓ D	✓ D P	✓ D	✓ D		✓ D	✓
	Non-TOU	ALVN, WLVN	✓ D	✓ D P	✓ D			✓ D	✓
Transformer	TOU	ATXT, WTXH ATXTS, WTXHS ATXTD, WTXHD	✓ D	✓ D P	✓ D	✓ D		✓ D	✓
	Non-TOU	ATXN, WTXN	✓ D	✓ D P	✓ D			✓ D	✓
High voltage	TOU	AHVT, WHVH AHVTS, WHVHS AHVTD, WHVHD	✓ D	✓ D P	✓ D	✓ D	✓ D	✓ D	✓
	Non-TOU	AHVN, WHVN	✓ D	✓ D P	✓ D			✓ D	✓
Zone substation	TOU	AZST, WZSH AZSTS, WZSHS	✓ D	✓ D P	✓ D	✓ D	✓ D	✓ D	✓

[10] D is distribution cost recovery and D P has both distribution and a pass-through cost recovery. There are no transmission prices included in the price categories.

Consumer group	Price category	Price category codes	Daily -FIXD $/day	Capacity -CAPY $/kVA/day	Volume - anytime -24UC $/kWh	Demand -DAMD $/kVA/day	Excess demand -DEXA $/kVA/day	Power factor -PWRF $/kVAr /day	Volume - injection -INJT $/kWh
Sub-transmission	TOU	ASTT, WSTH ASTTS, WSTHS	✓ D	✓ D P	✓ D	✓ D	✓ D	✓ D	✓

- The pass-through cost recovery is only as a capacity charge.
- The transmission cost recovery is not included as we have adopted a GXP Pricing Methodology since 1 April 2023 to recover transmission costs.

The zone substation and sub-transmission price categories are only TOU (no non-TOU option) and are priced the same across the Auckland and Northern networks. This is consistent with the transition towards aligning the other commercial consumer groups' prices between the networks.

We maintain a relativity in the capacity price levels between the commercial price categories, as shown in Table 7: Commercial capacity price relativities below, for example the high voltage capacity prices are 99% of transformer to low voltage price levels which are, in turn, 92% of low voltage price levels. This approach approximates the different costs of serving these consumer groups according to where they connect to the network.

Table 7: Commercial capacity price relativities

Consumer group	Capacity ($/kVA/day)
Transformer to low voltage	92%
High voltage to transformer	99%
Sub-transmission to zone substation	80%

PY2027 PRICE SETTING

PRICE CHANGES & PRICE SETTING COMPLIANCE

PRICE SETTING COMPLIANCE

Our prices comply with the price path set out in the DPP Determination[11]. To comply with the price path:

1. Our forecast revenue from prices must not exceed forecast allowable revenue (revenue cap).
2. Revenue cap equals the regulated distribution revenue, regulatory adjustments, wash-up account, forecast pass-through (e.g. transmission costs, council rates and statutory levies).
3. Forecast revenue from prices equals prices times forecasted quantities, subtracting forecasted other regulated income (e.g. forecasted loss on disposal) and revenue from large connection contracts (where we have nil).
4. Target revenue[12] means prices times forecasted quantities without subtracting forecasted other regulated income and it is a term referred often in other sections (e.g. COSM allocation). This is different to DPP3 where target revenue and forecast revenue from prices are the same.
5. For further information on how we comply with the price path and forecasted quantities used to determine prices, please refer to our price setting compliance statement. [13]

PRICE CHANGES

Prices are derived in reference to the revenue cap and forecasted quantities, explained above. Changes in the revenue cap and forecasted quantities will lead to price changes. The Commission sets our price path in a five-year cycle and 1 April 2026 is the second year of DPP4. The change in revenue cap (which determine how target revenue is set) this year is largely driven by the annual rate of change and the forecasted CPI. The increase in revenue cap[14] from $858.8m to $981.5m, together with the impact of change in forecasted quantities (6%), has resulted in a PY27 weighted average price increase (excluding transmission) of 7.8% for mass market, unmetered and commercial consumer groups. Weighted average price change is calculated by applying the 1 April 2026 prices to the forecast quantities of the same price category codes from the previous pricing year (base year), then comparing to the change in revenue by applying the 1 April 2025 prices to the same forecast quantities of the base year.

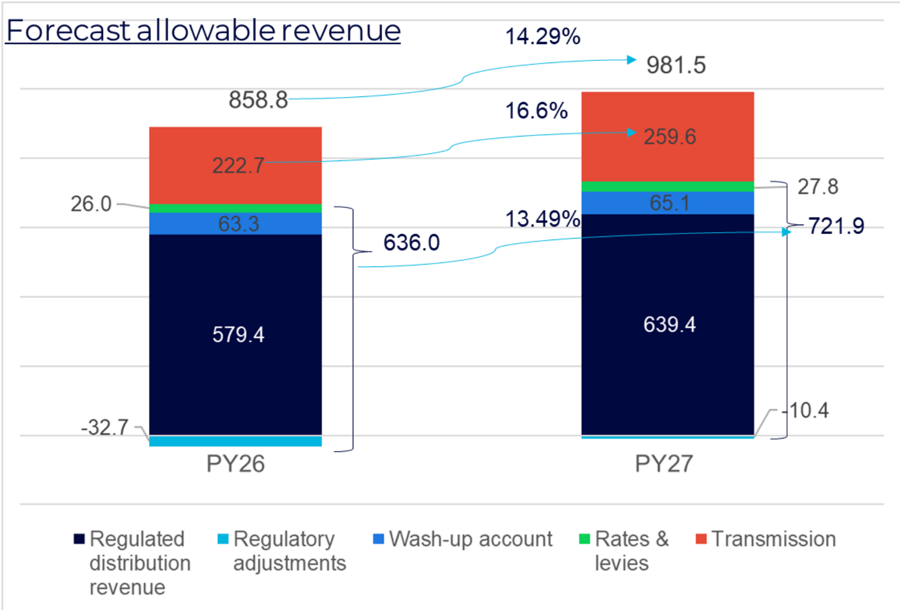
[11] Available at https://comcom.govt.nz/regulated-industries/electricity-lines/projects/2025-reset-of-the-electricity-default-price-quality-path?target=documents&root=363275
[12] Target revenue means the revenue that the EDB expects to obtain from prices. This means our prices times forecasted quantities, which is $982.8m for PY27 and $858.7m for PY26.
[13] Available at https://www.vector.co.nz/about-us/regulatory/disclosures-electricity/price-quality-path
[14] Please note that the revenue cap excludes the impact of forecasted gains and losses on disposed assets. As explained in bullet point 3 under "Price setting compliance", forecasted loss on disposal is deducted from forecast revenue from prices and that equates to $965.1m in PY27 and $841.3m in PY26.

In addition, we have performed bill impact analysis to assess the combined impacts of price and forecasted quantity changes, which takes into account the updated mass market TOU peak hours applicable from 1 April 2026. Our residential ICP bill impacts analysis (excluding transmission) indicates that 97% of residential ICPs have a bill impact less than $10 per month based on forecast profiles generated using historical consumption and the updated peak and off-peak consumption assumptions. Furthermore, the typical/median monthly bill change is approximately

Please note that the ICP bill impacts can potentially be reduced if consumption shifts from peak to off peak periods as chargeable quantities would reduce.

To quantify the change in the components of forecast allowable revenue (excluding transmission): regulated distribution revenue (+$60.0m), wash-up account and regulatory adjustments (+$24.0m), rates and levies (+$1.7m). Please refer to Figure 3

Figure 3 Forecast allowable revenue breakdown



Our transmission charges are bulk charged at GXP level to electricity retailers. This is a direct pass through of Transpower charges to Vector and the price change is a direct reflection of how Transpower charges Vector (+$36.9m increase). Please refer to Transpower's explanation of their charges here.

Residential low user prices are required to comply with the Low Fixed Charge (LFC) regulations[15]. For residential low user consumers, Vector has increased the fixed price component from 75 cents to 90 cents to reflect the phase-out provisions in the LFC. The LFC regulations will end on 1 April 2027.

Non-standard consumers are priced as per their contracts which have largely fixed prices. The price change for non-standard contracts is usually inflation adjustments or calculated in accordance with terms in the contract.

Our electricity prices that apply from 1 April 2026, including the previous year's prices that were effective from 1 April 2025, are set out in Appendix 2.[16]

[15] https://www.legislation.govt.nz/regulation/public/2004/0272/latest/dlm283614.html
[16] Our full price schedules are available at https://www.vector.co.nz/personal/electricity/about-our-network/pricing

TRANSMISSION PASS-THROUGH PRICING

We moved to a GXP based transmission pricing approach[17] on 1 April 2023 in response to Transpower's new Transmission Pricing Methodology (TPM) that was effective on the same date. Our approach determines the transmission pass-through cost prices by dividing the total amount of the Transpower monthly charges at each GXP for the upcoming pricing year by 100,000 to establish a price that would apply for each "1/1000th of a percentage share" of the charging unit. These prices are applied to each retailer or direct-bill end user's percentage share:

- Retailers and direct billed customers' GXP percentage shares are calculated using historic total energy usage (year to September 2025) based on the retailer ICP level submissions to Vector in the EIEP1 and EIEP3 format. The year to September 2025 was used so all months in the annual data include the three-month quantity wash-ups.
- ICPs are attributed to the retailer and GXP as at 31 December 2025 from EA registry-based data. The 31 December 2025 date was used so the ICP is attributed using the latest available information to minimise ICP switching impacts.
- Retailer and GXP volumes are the sum of the ICP volumes (year to September 2025) for their ICPs as at 31 December 2025.

Customer's annual transmission charges are calculated as follows:

$$Customer's\ annual\ transmission\ charges = Customer's\ GXP\ percentage\ share\ \times GXP's\ price\ for\ transmission\ \times 12 \times 100{,}000$$

Customers' GXP percentage shares are calculated as follows:

$$Customers' GXP\ percentage\ share = \frac{Customers' energy\ usage}{GXP's\ total\ energy\ usage}$$

GXP's price for transmission is calculated as follows:

$$GXP's\ price\ for\ transmission = \frac{(CC + BBC + RC + CRC + NIC)}{12\ \times 100{,}000}$$

Where:

CC	is the total of connection charges for the relevant GXP
BBC	is the total of benefit-based charges for the relevant GXP
RC	is the residual charge for the relevant GXP
CRC	is the (allocated) cap recovery charge for the relevant GXP
NIC	is the total of new investment charges for the relevant GXP

Annual transmission pass-through wash-up methodology

1. We will re-calculate the monthly amount by using actual volumes reported for each consumption month. The wash-up calculations will be completed after we receive the month 3 wash-up files.

[17] Please refer our 2024 pricing methodology for further explanation of these changes. Available at https://blob-static.vector.co.nz/blob/vector/media/vector-2023/electricity-pricing-methodology-2024.pdf

2. We will compare the re-calculated monthly amount to the actual billed amount and the difference will be the wash-up amount. After the end of each full pricing year, we will issue a wash-up invoice or credit note for the accumulated 12-month wash-up amounts. This will likely occur by July following the end of the pricing year.

3. Please refer to Table 8 indicative timing of washup-calculation.

Table 8 indicative timing of washup-calculation

<table>
<tr><td rowspan="2"></td><td colspan="12">Consumption months in PY26/27</td></tr>
<tr><td>Apr-26</td><td>May-26</td><td>Jun-26</td><td>Jul-26</td><td>Aug-26</td><td>Sep-26</td><td>Oct-26</td><td>Nov-26</td><td>Dec-26</td><td>Jan-27</td><td>Feb-27</td><td>Mar-27</td></tr>
<tr><td>Monthly Invoice</td><td colspan="12">Fixed monthly GXP-based transmission charge. Based on the existing method (share of customers as at 31 Dec 2025, based on historical volume). Invoices sent by working day 10 following end of consumption month.</td></tr>
<tr><td>Wash-up calculations</td><td colspan="12">Monthly wash-up calculation performed by Vector using actual volumes reported for each consumption month. Wash-up calculations will be completed after Vector receives the month 3 wash-up files – e.g. for the April 26 consumption month the transmission wash-up calculation will be completed by Vector in August 26.</td></tr>
<tr><td>Wash-up calculation month</td><td>Jul-26</td><td>Aug-26</td><td>Sep-26</td><td>Oct-26</td><td>Nov-26</td><td>Dec-26</td><td>Jan-27</td><td>Feb-27</td><td>Mar-27</td><td>Apr-27</td><td>May-27</td><td>Jun-27</td></tr>
<tr><td>Wash-up tracking update to retailers</td><td colspan="3">Update retailer advising their wash-up calculation for Q1 of pricing year.
We aim to provide Q1 update in October 26.</td><td colspan="3">Update retailer advising their wash-up calculation for Q2 of pricing year.
We aim to provide Q2 update in January 27.</td><td colspan="3">Update retailer advising their wash-up calculation for Q3 of pricing year.
We aim to provide Q3 update in April 27.</td><td colspan="3">Update retailer advising their wash-up calculation for Q4 of pricing year.
We aim to provide Q4 update in July 27.</td></tr>
<tr><td>Wash-up Invoice or Credit Note</td><td colspan="12">Annual wash-up invoice or credit note for the accumulated wash-up amount for the full pricing year. Invoice or credit notes will be issued to retailers following completion of pricing year and all relevant wash-up calculations completed. Likely issued in July 27.</td></tr>
</table>

Transpower adjustment events

Under clause 75 of schedule 12.4 of the Transmission Pricing Methodology[18], Transpower can adjust relevant transmission charges from the date of an adjustment event. To mirror and recover Transpower's adjustment events, we included the forecasted adjustment event charges for the pricing year.

Our forecast is based on the best available information notified by Transpower at the time of pricing. We may adjust the transmission prices during the pricing year to reflect the adjustment events that are not included in the forecast amounts, providing any change meets the Commission's price path requirements and is permitted by Vector's default distribution agreement[19].

The GXP transmission prices are in Appendix 2.

18 https://www.ea.govt.nz/documents/931/EIPCA_Transmission_Pricing_Methodology_2022_amendment_-_Certified_instrument.pdf
19 https://blob-static.vector.co.nz/blob/vector/media/vector-2024/vector-dda-v2-(website).pdf

NEGATIVE INJECTION CHARGE

Vector's pricing methodology includes a negative charge for injection (an 'injection credit') for price categories with eligibility criteria designed to target residential and small business/general[20] (mass-market) consumers, consistent with Code[21] clause 12A.7.

<u>When the injection negative charge applies (time periods / circumstances)[22]</u>

For eligible mass-market price categories, the injection credit applies to injection recorded during Vector's defined peak time periods[23] for the relevant price category i.e., the same peak periods as TOU pricing. The injection credit is implemented as a negative volumetric rate (c/kWh).

<u>Basis of the negative charge[24]</u>

For the pricing year beginning 1 April 2026, Vector applies a long run marginal cost (LRMC)-based approach under Code clause 12A.7(1)(b)(i). LRMC is estimated using the Electricity Network Aotearoa (ENA) LRMC spreadsheet model prepared using a long run average increment cost (LRAIC) methodology, populated with Vector inputs. Vector tested the model using (i) sensitivity analysis of key assumptions using Vector's asset management plan (AMP) forecast inputs, and (ii) range testing using historical AMP forecasts to understand variability in modelled LRMC outcomes.

Vector's LRMC value used for pricing purposes is $119/kW-year. This value sits within the distribution of LRMC outcomes produced by the ENA model using AMP forecast sets and is considered a reasonable representation of the long-run marginal cost.

<u>How LRMC was calculated[25]</u>

Vector's LRMC is calculated on the whole-network basis and uses demand-driven capital expenditure (capex) forecasts[26], peak demand forecasts and the defined peak hours, along with asset life assumptions. The model annualises and discounts capex, adds incremental operating expenditures (opex), and unitises total incremental costs using forecast demand to produce LRMC in $/kW-year (and then $/kWh for the peak hours).

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[20] From 1 April 2026 (amended 21 January 2026), clause 12A.7 requires negative charges at a minimum for price categories targeting residential consumers and business consumers with connection capacity ≤45 kVA, and only for DG with maximum deliverable generation capacity ≤45 kW (total across three phases); Vector's general price categories extend to ≤69 kVA, and we will monitor outcomes and revise settings post-implementation if needed.
[21] Part 12A—Distributor agreements, arrangements, and other provisions | Electricity Authority
[22] Code clause 12A 7.3(c)
[23] For the defined peak periods, please refer to page 13
[24] Code clause 12A.7(1)(b)(i)
[25] Code clause 12A.7(3)(a)(i)
[26] This is gross of capital contributions.

How LRMC was converted into a negative charge for injection[27]

Vector converts LRMC ($/kW-year) into an injection negative charge ($/kWh) by dividing the number of peak-hours in the defined injection peak periods. Vector then applies an injection adjustment factor of 50% to reflect the specific characteristics of injection and to have regard to transaction costs, consumer impacts, uptake incentives, and network stability.

Injection negative charge rate (c/kWh) = – (LRMC per peak kWh for injection negative charge) × 0.5

We determined that a 50% adjustment factor is a balanced approach, recognising that injections are not always equivalent to avoided peak demand or firm, dispatchable supply. Unmanaged injection can also result in additional network costs, such as voltage and protection impacts. This approach takes into account the guidance from the Electricity Authority that recommends starting with a relatively high adjustment factor initially, then refining it as better data and consumer feedback become available. Vector will review this factor over time as experience, data and operational practices develop.

Payment mechanism[28]

The injection negative charge may be met by way of a credit against amounts owed to Vector by the retailer/trader for the relevant ICPs (i.e., offset against distribution charges).

27 Code clause 12A.7(3)(a)(ii)
28 Code clause 12A.7(2)

PRICE CHANGES AND CRITERIA UPDATED

We have made the following price changes, and updated relevant criteria, that will be applicable from 1 April 2026 as shown in Table 9 and Table 10 below. These are not deemed as structure changes as no consumer groups are combined or reduced.

Table 9: Price changes

Changes	Rationale	Effect/customer impact
Adjusted the low residential user fixed daily line charge (from $0.75 to $0.90 per day)	To reflect the amended low user fixed charge regulations that allows annual increases in the proportion of revenue recovered through fixed charges.	Increases the daily fixed charge for low user customers by $0.15/day. Bill impact depends on consumption profile; Noting that low user volumetric prices decrease to maintain parity with standard users at 8,000 kWh annual consumption.
Demand component set to zero for Commercial DER	Commercial DER ICPs are approved on the basis they will comply with dynamic operating envelopes and work within Vector's DERMS. Feedback from retailers has indicated that retaining a demand charge reduces the value proposition of the tariff and therefore discourages participation; the goal is to remove demand charges to improve uptake.	Reduces bills for approved low voltage, transformer, and high voltage Commercial DER customers if retailers pass through the zero price demand component. Improves the participation incentive/value proposition for Commercial DER.
Introduce a negative injection charge for TOU mass-market ICPs during peak hours	Implements the Electricity Authority requirement to incentivise eligible residential and general ICPs that inject during peak periods, and aligns injection peak periods with consumption peak periods (to reduce complexity and improve signal consistency)	Creates an injection negative charge for eligible TOU customers when they export during peak periods (applied as a negative volumetric injection rate). From 1 April 2026, TOU injection prices are split into IJPK (peak injection) and IJOP (off-peak injection); anytime customers are not TOU-split and INJT continues.

Table 10: Criteria updated

Changes	Rationale	Effect/customer impact
Mass market TOU hours updated by adding 9–10pm and adding weekends	Following low-voltage network consumption data analysis, Vector identified evolving network usage trends and has realigned peak timing to better reflect low-voltage network peaks, including introducing weekend and 9:00–10:00pm peak pricing periods.	Customer bill impact analysis (excluding transmission) indicates the changes result in 97% of residential ICPs having a bill impact of less than $10 per month (based on historical consumption and updated peak/off-peak assumption profiles). Better targeted peak times reduces network investment resulting in long term benefits to consumers.
Mass market DER criteria amended	To promote adoption and reliable performance of smart load control, Vector is expanding residential (and general) DER eligibility to include devices that can be remotely managed (turned off or reduced) by retailers, supporting increased load management capability and performance across Vector's network.	Eligible ICPs receive an annual discount of approximately $50, in addition to any savings from shifting load to off-peak periods. This acts as an option/certainty premium to support effective load management and help keep demand outside Vector's critical peak periods.

CONSULTATION, DISCUSSION, GOVERNANCE, & COMPLIANCE TIMEFRAME

Vector's price setting timeline, including governance, consultation, and notification, is outlined in the table below. Vector did not directly seek the views of consumers when setting prices or price structures as Vector largely bills retailers and not end users. Vector has no control on how or if its price changes are passed on to consumers. Rather, we consulted with Entrust, whose beneficiaries are mass market consumers on the Auckland network and retailers. Retailers have full discretion as to whether they pass our prices through to end users – some retailers do, some do not.

Table 11: Timeframe for Vector's electricity price setting

Activity	Date	Notes
First PY27 pricing initiative discussion	March to April 2025	Letters sent to and met with key retailers on the upcoming pricing direction
Discussion and preparation	August 2025 to October 2025	Internal discussions on potential pricing innovations
Second PY27 pricing initiative discussion	September 2025	Discuss potential pricing options with key retailers and sought feedback
Board presentation	September and October 2025	Price initiatives discussed with Board
Draft prices determined for consultation	Late October 2025	Quantity forecasts derived
Entrust consultation	Early to mid-November 2025	Material provided to Entrust followed by presentation
Retailer consultation	Mid-November to early December 2025	Three-week consultation period, meetings with key retailers
Board presentation	Early December 2025	Price change impact discussed with Board
Auditor review	December 2025	Findings prior to final price approval
Final price approval	December 2025	Entrust and retailer feedback considered. Individual responses provided to retailers on their feedback. Board approved a range of recommendations.

Activity	Date	Notes
Retailer and Entrust price notification	December 2025	Final notification for standard tariffs and price schedules
Briefing regulatory and other relevant stakeholders	December 2025	Met with Commission, Electricity Authority and Energy Efficiency & Conservation Authority regarding our PY27 pricing initiatives.
Non-standard prices and transmission charge notification	Late January 2026	Non-standard prices notified to consumers and transmission charges notified to retailers and direct billed consumers
Board approval of compliance and disclosure material	Late February 2026	Approval of the price setting compliance statement and pricing methodology for publication and provision to Commission
Public disclosure	Early March 2026	20 working days prior to price change
Price changes	1 April 2026	Price change implemented

TARGET REVENUE AND ITS CATEGORISATION

Our COSM is used to allocate target revenue to consumer groups using various cost drivers. The model structure is outlined in Figure 4.

Target revenue is the total revenue we expect to recover from our prices (complying with the regulated price path) and our forecasted quantities. The total target revenue for PY27 is $982.8m ($858.7m for PY26).

The total target revenue is broken down into the key components required to cover the costs and return on investment associated with the provision of electricity distribution services as shown below in Figure 6

The key components are categorised by cost driver i.e. either 'asset', 'non-asset', 'transmission' or 'return'. These categorisations are summarised in Figure 5 and determines the way that the target revenue is allocated to consumer groups.

Figure 4: COSM structure

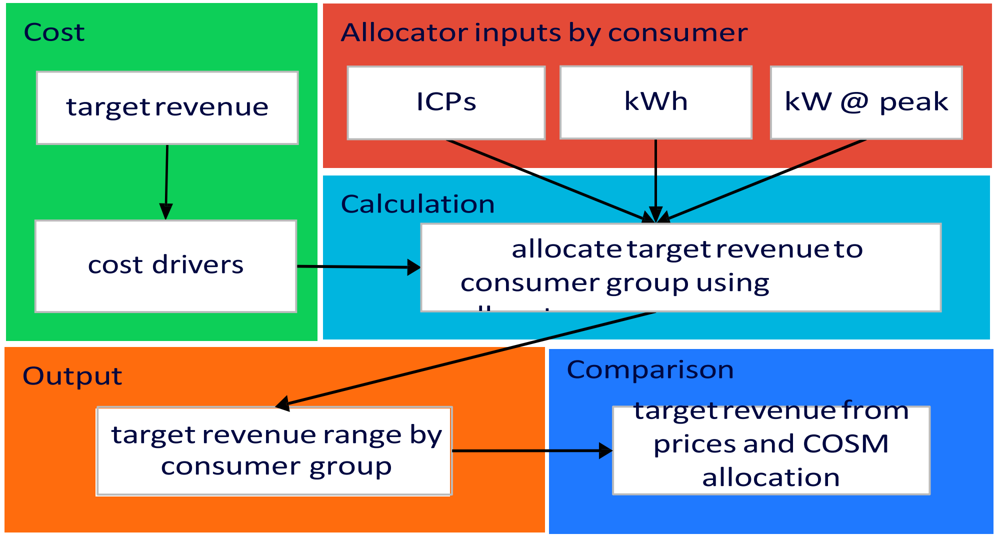


Figure 6: Target revenue by key components

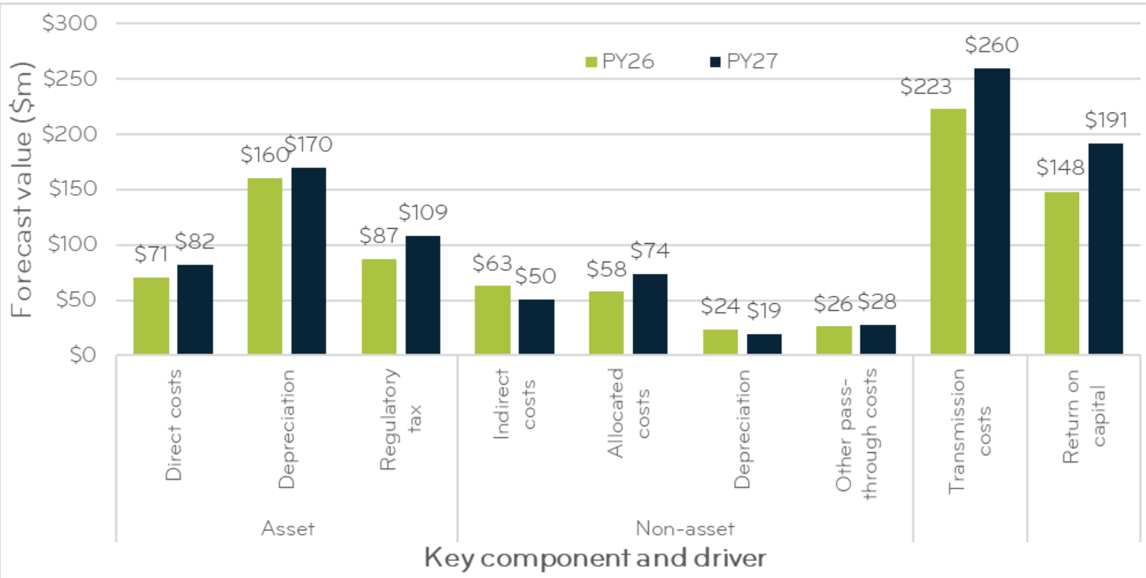
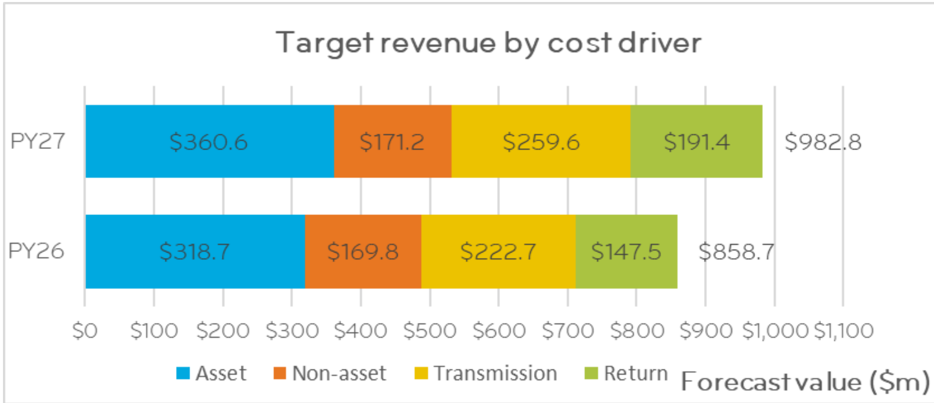


Figure 5: Target revenue by cost driver



COST DRIVERS

The key components categorised as 'asset costs' are those associated with expenditure and return on the electricity distribution network assets. We have grouped these network assets into five distinct categories as shown in Table 12 and Figure 7.

We assume that costs associated with assets are incurred in proportion to the value of the assets. For example, as Asset Category A3 assets make up 37% of the asset value in our Regulatory Asset Base (RAB), we assume that 37% of maintenance costs will be associated with Asset Category A3 assets.

Figure 7: Asset and customer location

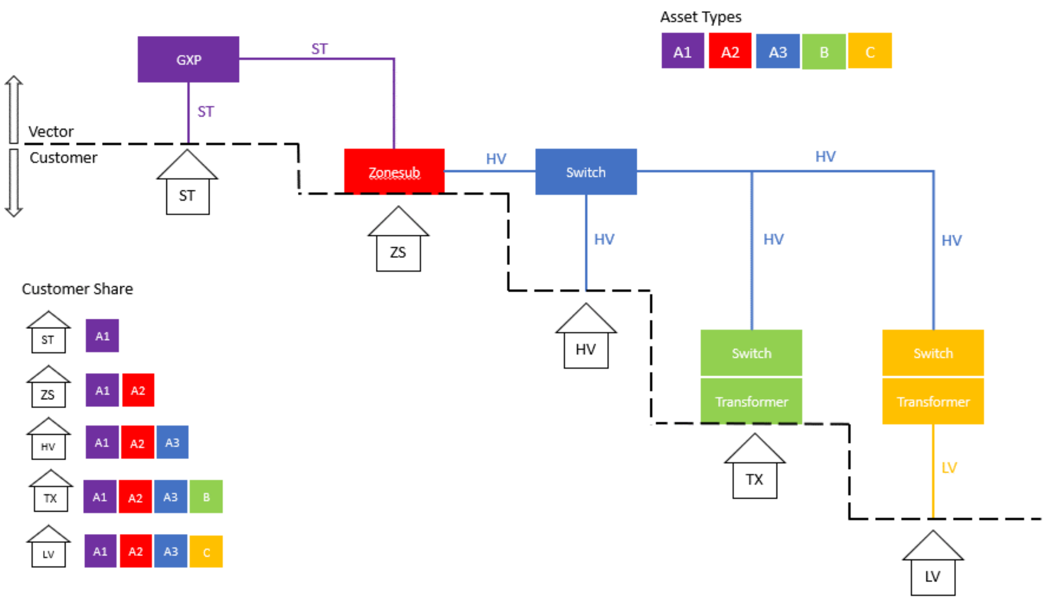


Table 12: Asset categorisation

Category	Assets	Consumer Group	Asset value [29] (RAB)	
A1	• Sub-transmission lines / cables	All	$655m	16%
A2	• Land and buildings • Zone-substations • Sub-transmission switch gear	All except ST	$797m	20%
A3	• HV lines / cables	All except ST and ZS	$1,524m	37%
B	• Distribution transformers and substations that have no Vector-owned low voltage lines / cables leaving them	Transformer	$82m	2%
C	• Distribution transformers and substations that: ○ have Vector-owned low voltage lines leaving the substation, or ○ supply multiple end-users connected at low voltage • Low voltage assets	Low voltage, unmetered, mass market	$1,024m	25%

[29] The values are weighted averages of the last five years' worth of data, with each year being weighted twice the previous year

COST DRIVER ALLOCATION APPROACHES

A key feature of an electricity distribution network is interconnected assets. Many consumers on the network share assets and it is difficult to identify precisely who benefits from which assets. While this means that the allocation of target revenue between consumer groups can be made in many ways, it also means that the cost of providing the network is shared widely and therefore the cost of network services is generally low for each consumer. The cost drivers of ‘asset’, ‘non-asset’, ‘transmission’ and ‘return’ are applied to the combined Northern and Auckland networks. Our COSM allocates the recovery of the $982.8m to consumer groups using the cost drivers as summarised in Table 13.

Table 13: Cost drivers used in COSM

<table>
<tr><th>Consumer group</th><th colspan="5">Asset</th><th>Non-asset</th><th>Transmission</th><th>Return</th></tr>
<tr><td></td><td>A1</td><td>A2</td><td>A3</td><td>B</td><td>C</td><td></td><td></td><td></td></tr>
<tr><td>Amount</td><td>$57.9m</td><td>$70.4m</td><td>$134.5m</td><td>$7.3m</td><td>$90.5m</td><td>$171.2m</td><td>$259.6m</td><td>$191.4m</td></tr>
<tr><td>Mass market</td><td rowspan="7">kW or kWh</td><td rowspan="6">kW or kWh</td><td rowspan="5">kW or kWh</td><td rowspan="3">n/a</td><td rowspan="3">kW or kWh</td><td rowspan="7">ICPs or kWh</td><td rowspan="7">n/a</td><td rowspan="7">Asset value</td></tr>
<tr><td>Unmetered</td></tr>
<tr><td>Low voltage</td></tr>
<tr><td>Transformer</td><td>Direct</td><td rowspan="4">n/a</td></tr>
<tr><td>High voltage</td><td rowspan="3">n/a</td></tr>
<tr><td>Zone substation</td><td rowspan="2">n/a</td></tr>
<tr><td>Sub-transmission</td><td>n/a</td></tr>
</table>

We aim to allocate asset-related costs on the basis of a consumer group’s usage (in percentage terms[30]) of the assets during peak periods, as this usage drives the need for, and the size of, the assets.

‘A1, A2, A3 and C asset related costs’ are allocated using a combination of contribution to peak usage (kW, network peak from 2021) and annual consumption. These cost allocators measure peak usage and the customer size.

‘B asset related costs’ do not require an allocation approach as they are used by one consumer group (transformer consumers).

‘Non-asset costs’ can be broadly summarised as overhead costs and pass-through costs (other than transmission costs). Costs categorised as ‘non-asset’ have no direct cost driver. We have chosen to use annual consumption and the number of consumers as the cost allocators.

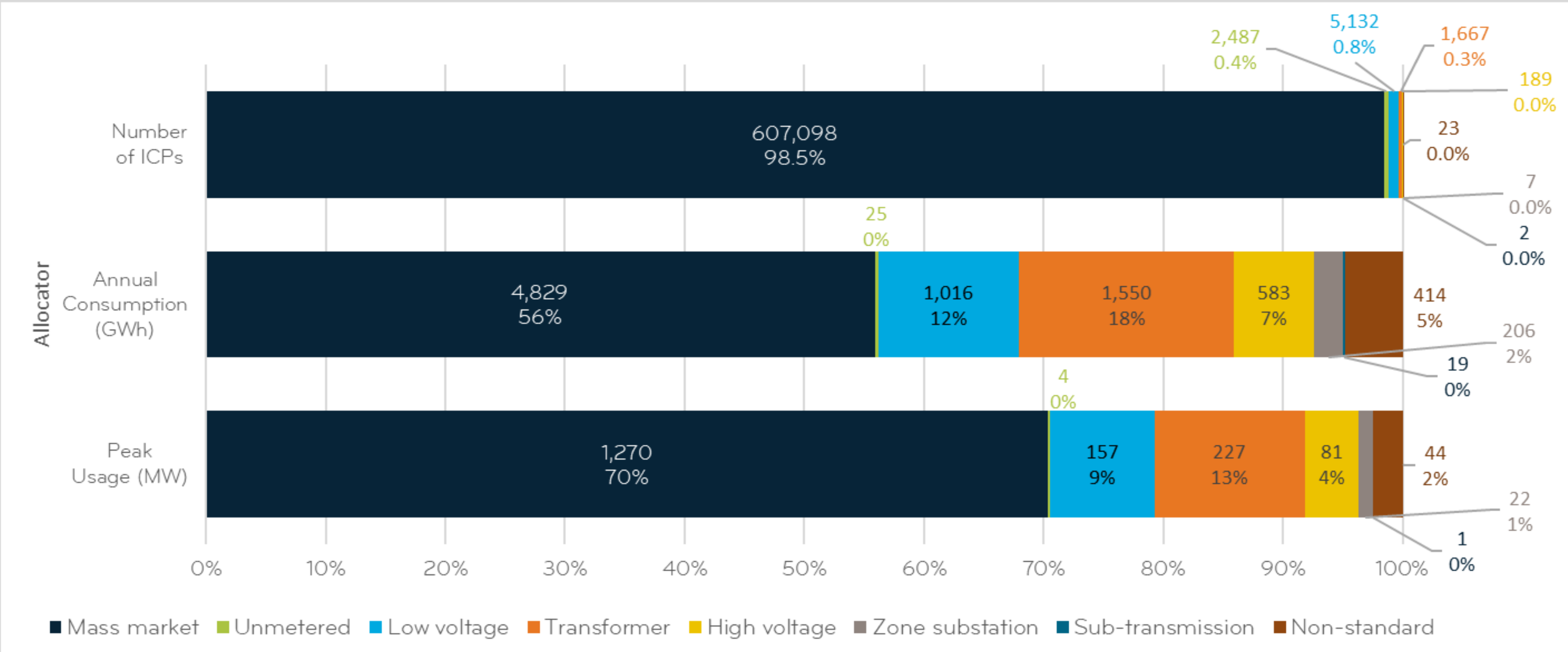
Costs categorised as ‘transmission’ are transmission charges from Transpower that we pass through to retailers. Transmission costs are part of Vector’s target revenue but are excluded from the COSM as they are pass-through in bulk to the retailers/direct billed customers rather than being allocated to consumer groups.

[30] Weighted average of last five year’s values from the billed quantities in Schedule 8 of our annual Electricity Information Disclosures (available at https://www.vector.co.nz/about-us/regulatory/disclosures-electricity/financial-and-network-information), with each year being weighted twice the previous year

‘Return’ is the return on capital earned by Vector on its assets. A consumer groups’ asset values are calculated in the same way as ‘asset’ related costs are. ‘Return’ is apportioned across the consumer groups’ asset values.

The sub-transmission consumer group lacks sufficient historic allocators to determine its target revenue allocation and prices, so the COSM couldn’t be applied in the same manner as for other consumer groups. As a proxy for sub-transmission cost allocators, we estimated them based on the forecasted usage of sub-transmission consumer groups.

Figure 7 COSM allocation values and usage percentage



DISTRIBUTION TARGET REVENUE ALLOCATION & PRICE COMPARISON

The result of using the different allocators across the categories, creates a target revenue range by consumer group as the use of different allocators gives rise to different target revenue allocation results. The bands represent the lower and upper bounds of the different allocation approaches, as shown in Figure 8 which shows target revenue calculated from PY27 prices by consumer group compared with the COSM allocations. The result is that PY27 prices produce forecasts that are in or near an acceptable range when compared to target revenue allocations.

The pricing for non-standard consumers is calculated as per their contracts and is separate from the other consumer groups. The COSM is calibrated to produce the forecasted distribution target revenue of $7.6m (0.8%) to be recovered from the 15 non-standard consumers (21 ICPs).

Price setting is an iterative process, where the prices are only finalised once the price path compliance is managed, bill impacts are fair and tolerable, and prices deliver revenue from each consumer group consistent with their target revenue allocation.

The proportion of the aggregated price categories' target revenue is shown by price component in Figure 9. All price categories within the aggregation have similar proportioned price components. Please see Appendix 2 for the proportion of target revenue split by individual price category and price component.

Figure 8 PY27 distribution and other pass-through target revenue from prices compared with COSM allocations

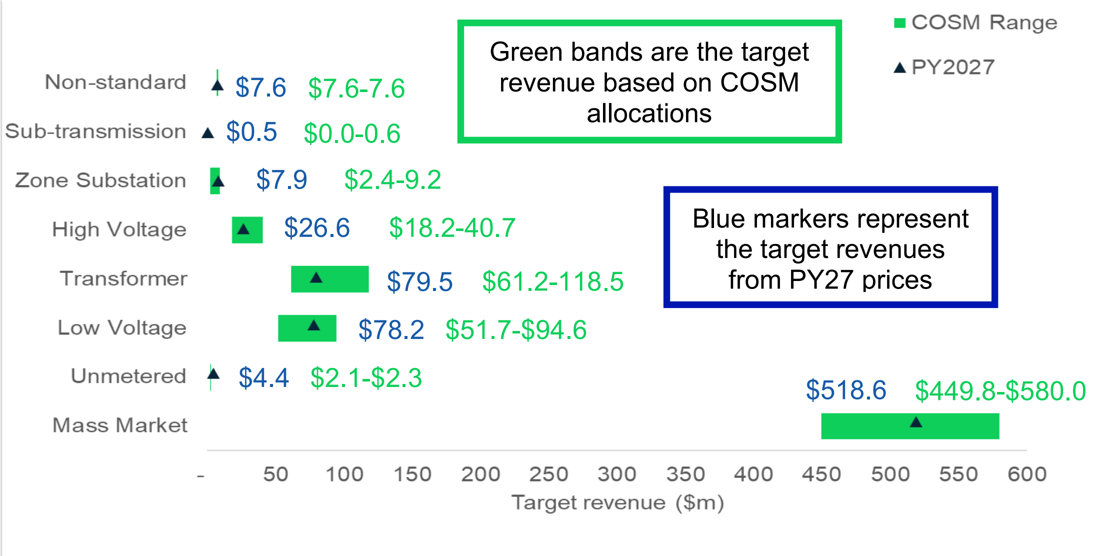
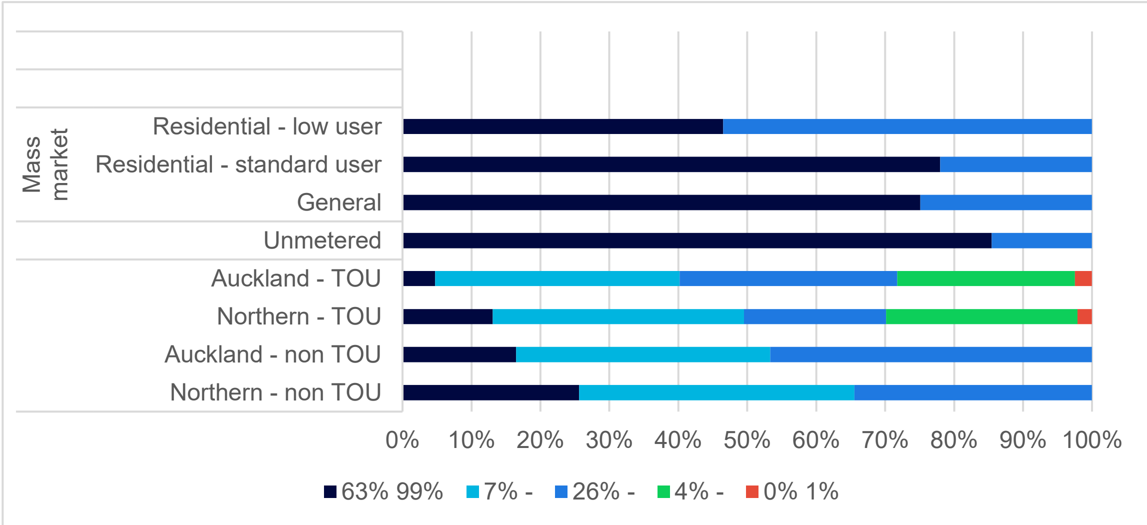


Figure 9 Proportion of PY27 target revenue by price component and category



POLICIES & OBLIGATIONS

NON-STANDARD CONTRACTS & DISTRIBUTED GENERATION POLICIES

Table 14: Criteria for non-standard contracts

Approach	Description
Criteria	For any new investments required by consumers, we apply our connection pricing policy. Our policy for determining connection charges on our electricity distribution network is available at http://vector.co.nz/disclosures/electricity/capital-contributions. When a new investment is recovered through connection charges, standard pricing applies unless otherwise agreed with Vector. Historical investments not recovered through connection charges may be subject to non-standard contracts allowing for non-standard prices and tailored commercial arrangements to be applied to individual consumers.
Methodology	For determining prices for consumers subject to non-standard contracts, we use actual costs and/or allocated costs derived from an allocation model to determine prices. This allocation model is similar to the COSM used in determining standard pricing.

Approach to pricing distributed generation

Our policies and procedures for installation and connection of distributed generation are in accordance with the requirements of Part 6 (Connection of distributed generation) of the Electricity Industry Participation Code 2010 (the Code).

We are permitted to charge each distributed generator prior to them connecting to the network based on the fees set out in Part 6 of the Code. We do not make Avoided Cost of Distribution or Avoided Cost of Transmission (ACOT) payments to any distributed generators.[31]

To date, given the small number of distributed generation connections, we have not identified any material short run incremental costs from the injection of energy into the network. Accordingly, the injection price for distributed generators continues to be $0.0000/kWh from 1 April 2026. As more distributed generation connects, this may require more in-depth consideration and, as a result, pricing may change.

Separately, from 1 April 2026, Vector introduced negative injection prices for eligible residential and general mass market TOU ICPs in response to new Electricity Authority requirements. TOU injection prices are split into peak injection (IJPK) and off-peak injection (IJOP). Anytime mass market ICPs are not affected and INJT continues to apply.

[31] Further information on our policies for distributed generation can be found at https://www.vector.co.nz/personal/electricity/distributed-generation. In previous years, Vector has made ACOT payments, but this has stopped from 1 April 2023 as per the EA's decision.

OBLIGATIONS AND RESPONSIBILITIES TO CONSUMERS

For PY27, our obligations and responsibilities to consumers in the event that the supply of electricity lines services to them is interrupted have no implications for determining prices. A summary of our obligations and responsibilities to consumers subject to non-standard contracts on our network (in the event that the supply of electricity lines services to the consumer is interrupted) is provided in Table 15. Our standard contract terms and non-contract terms are also compared.

Table 15: Summary of our obligations and responsibilities to consumers

	Planned interruption notice	Unplanned interruption notice	Fault restoration	No. of interruptions per annum	No. of consumers
Standard	4 working days	Within 20 minutes to the retailer	CBD: 2 hours	CBD and Urban: 4	Approx 643,000
			Urban: 2.5 hours		
			Rural: 4.5 hours	Rural: 10	
Non-standard	1 April each year, or 10 working days	As soon as practicable	2 hours	1 unplanned	1
	1 November each year	As soon as practicable	Priority	Not stated	5
	10 working days	As soon as practicable	3 hours	Not stated	4
	10 working days	Not stated	Not stated	Not stated	1
	4 working days	As soon as practicable	3 hours	Not stated	8
	7 working days	As soon as practicable	Priority	3 planned	2

APPENDICES

APPENDIX 1 – GLOSSARY

Word	Definition
Distributed generator	A party with whom we have an agreement for the connection of plant or equipment to our electricity distribution network where the plant or equipment is capable of injecting electricity into our distribution network
EIEP1 & EIEP3	Under the Regulated electricity information exchange protocols (EIEP), EIEP1 provides detailed ICP billing and volume information and EIEP3 provides half hour metering information
Forecast allowable revenue	Refer to 3.1.1 (3) of the Electricity Distribution Services Input Methodologies (IM review 2023) Amendment Determination 2023[32] (Input Methodologies).
Forecast net allowable revenue	Refer to 3.1.1 (4) and (5) of the Input Methodologies.
Installation control point number (ICP)	An ICP is a physical point of connection on a local network which a distributor nominates as the point at which a retailer will be deemed to supply electricity to a consumer
kVA	kVA is kilovolt–ampere (amp), a measure of apparent power being the product of volts and amps. Used for the measurement of capacity and demand for pricing
kWh	kWh is kilowatt-hour, a unit of energy being the product of power in watts and time in hours. Used for the measurement of consumption for volumetric prices
kVAr	kVAr is kilovolt ampere reactive, is a unit used to measure reactive power in an AC electric power system. Used for the measurement of power factor in pricing
kVArh	kVArh is kilovolt ampere reactive hour, a unit of energy being the product of reactive power in kVAr and time in hours. Used for the measurement of power factor in pricing
Price categories	Price categories are the relevant price plan (or tariff) from the price schedule that define the line prices applicable to a particular ICP.
Price components	Price components are the various prices that constitute the components of the total prices paid, or payable, by a consumer
PY27 & PY26	Pricing year (PY) is the 12-month period from 1 April to 31 March each year. PY27 is 1 April 2026 to 31 March 2027. PY26 is 1 April 2025 to 31 March 2026
Regulatory Asset Base (RAB)	RAB broadly represents the amount we have invested in our regulated network, indexed by inflation and adjusted for depreciation
Regulatory adjustments	Regulatory adjustments include incremental rolling incentive scheme (IRIS) and quality incentive adjustment.

[32] Available at https://comcom.govt.nz/__data/assets/pdf_file/0030/337683/Electricity-Distribution-Services-Input-Methodologies-IM-Review-2023-Amendment-Determination-2023.pdf

APPENDIX 2 – LINE CHARGE PRICES FROM 1 APRIL 2026

ICP based line charges

Distribution line charge prices for Auckland network residential and general (excluding GST) ICPs from 1 April 2026 ***(previous price if changing)***

					Daily FIXD $/day		Daily FIXD $/day /fitting		Volume anytime 24UC $/kWh		Volume anytime AICO $/kWh		Volume off-peak OFPK $/kWh		Volume peak PEAK $/kWh		Injection off-peak IJOP $/kWh	Injection peak IJPK $/kWh	Injection anytime INJT $/kWh	
Consumer group / type	Price category type	Price category description	Price category code	Estimate ICP no (year avg. 1 April 2026)	PY27	*previous price if changing*	PY27	*previous price if changing*	PY27	*previous price if changing*	PY27	*previous price if changing*	PY27	*previous price if changing*	PY27	*previous price if changing*	PY27	PY27	PY27	*previous price if changing*
Residential - low user	Time of use	Controlled	ARHLC	135,421	0.9000	*0.7500*							0.0457	*0.0444*	0.1504	*0.1575*	0.0000	(0.0524)		*0.0000*
		DER	ARHLD	3,915	0.9000	*0.7500*							0.0393	*0.0381*	0.1440	*0.1512*	0.0000	(0.0524)		*0.0000*
		Uncontrolled	ARHLU	65,507	0.9000	*0.7500*							0.0466	*0.0454*	0.1513	*0.1585*	0.0000	(0.0524)		*0.0000*
	Anytime (Closed to half hourly (HH) meters, except by exemption)	Controlled	ARNLC	6,096	0.9000	*0.7500*					0.0685	*0.0632*							0.0000	
		Uncontrolled	ARNLU	2,792	0.9000	*0.7500*			0.0694	*0.0642*									0.0000	
Residential – standard user	Time of use	Controlled	ARHSC	65,189	1.9020	*1.7253*							0.0000		0.1047	*0.1131*	0.0000	(0.0524)		*0.0000*
		DER	ARHSD	1,885	1.7620	*1.5853*							0.0000		0.1047	*0.1131*	0.0000	(0.0524)		*0.0000*
		Uncontrolled	ARHSU	47,229	1.9220	*1.7453*							0.0000		0.1047	*0.1131*	0.0000	(0.0524)		*0.0000*
	Anytime (Closed to half hourly (HH) meters, except by exemption)	Controlled	ARNSC	5,319	1.9020	*1.7253*					0.0228	*0.0188*							0.0000	
		Uncontrolled	ARNSU	3,763	1.9220	*1.7453*			0.0228	*0.0188*									0.0000	
General	Time of use	Uncontrolled	ABSH	31,549	2.3928	*2.1443*							0.0000		0.1047	*0.1131*	0.0000	(0.0524)		*0.0000*
		DER	ABSHD	-	2.2328	*1.9843*							0.0000		0.1047	*0.1131*	0.0000	(0.0524)		*0.0000*
	Anytime (Closed to half hourly (HH) meters, except by exemption)	Uncontrolled	ABSN	4,850	2.3928	*2.1443*			0.0228	*0.0188*									0.0000	
Unmetered	Anytime	Uncontrolled	ABSU	1,763			0.0824	*0.0754*	0.0273										0.0000	

Please note that previously residential and general injection prices were all zero regardless of peak or off-peak periods. From 1 April 2026, TOU injection prices will be split into peak injection (IJPK) and off-peak injection (IJOP) prices. Anytime customers are not affected and INJT continues to apply.

Distribution line charge prices for Northern network residential and general ICPs from 1 April 2026 *(previous price, if changing)*

					Daily		Daily		Volume anytime		Volume anytime		Volume off-peak		Volume peak		Injection off-peak	Injection peak	Injection anytime	
					FIXD		FIXD		24UC		AICO		OFPK		PEAK		IJOP	IJPK	INJT	
					$/day		$/day /fitting		$/kWh		$/kWh		$/kWh		$/kWh		$/kWh	$/kWh	$/kWh	
Consumer group / type	Price category type	Price category description	Price category code	Estimate ICP no (year avg. 1 April 2026)	PY27	*previous price if changing*	PY27	*previous price if changing*	PY27	*previous price if changing*	PY27	*previous price if changing*	PY27	*previous price if changing*	PY27	*previous price if changing*	PY27	PY27	PY27	*previous price if changing*
Residential - low user	Time of use	Controlled	WRHLC	79,782	0.9000	*0.7500*							0.0466	*0.0454*	0.1513	*0.1585*	0.0000	(0.0524)		*0.0000*
		DER	WRHLD	2,308	0.9000	*0.7500*							0.0393	*0.0381*	0.1440	*0.1512*	0.0000	(0.0524)		*0.0000*
		Uncontrolled	WRHLU	42,507	0.9000	*0.7500*							0.0466	*0.0454*	0.1513	*0.1585*	0.0000	(0.0524)		*0.0000*
	Anytime (Closed to half hourly (HH) meters, except by exemption)	Controlled	WRNLC	2,663	0.9000	*0.7500*					0.0694	*0.0642*							0.0000	
		Uncontrolled	WRNLU	1,017	0.9000	*0.7500*			0.0694	*0.0642*									0.0000	
Residential – standard user	Time of use	Controlled	WRHSC	65,500	1.9220	*1.7453*							0.0000		0.1047	*0.1131*	0.0000	(0.0524)		*0.0000*
		DER	WRHSD	1,894	1.7620	*1.5853*							0.0000		0.1047	*0.1131*	0.0000	(0.0524)		*0.0000*
		Uncontrolled	WRHSU	38,003	1.9220	*1.7453*							0.0000		0.1047	*0.1131*	0.0000	(0.0524)		*0.0000*
	Anytime (Closed to half hourly (HH) meters, except by exemption)	Controlled	WRNSC	2,509	1.9220	*1.7453*					0.0228	*0.0188*							0.0000	
		Uncontrolled	WRNSU	1,817	1.9220	*1.7453*			0.0228	*0.0188*									0.0000	
General	Time of use	Uncontrolled	WBSH	18,839	2.3928	*2.1443*							0.0000		0.1047	*0.1131*	0.0000	(0.0524)		*0.0000*
		DER	WBSHD	-	2.2328	*1.9843*							0.0000		0.1047	*0.1131*	0.0000	(0.0524)		*0.0000*
	Anytime (Closed to half hourly (HH) meters, except by exemption)	Uncontrolled	WBSN	3,444	2.3928	*2.1443*			0.0228	*0.0188*									0.0000	
Unmetered	Anytime	Uncontrolled	WBSU	755			0.0824	*0.0754*	0.0273										0.0000	

Please note that previously residential and general injection prices were all zero regardless of peak or off-peak periods. From 1 April 2026, TOU injection prices will be split into peak injection (IJPK) and off-peak injection (IJOP) prices. Anytime customers are not affected and INJT continues to apply.

Distribution line charge prices for Auckland network commercial ICPs (excluding GST) from 1 April 2026 *(previous price, if changing)*

					Daily		Volume anytime		Capacity		Demand		Excess Demand	Power factor	Injection anytime
					FIXD		24UC		CAPY		DAMD		DEXA	PWRF	INJT
					$/day		$/kWh		$/kVA/day		$/kVA/day		$/kVA/day	$/kVAr/day	$/kWh
Consumer group / type	Price category type	Price category description	Price category code	Estimate ICP no (year avg. 1 April 2026)	PY27	*previous price if changing*	PY27	*previous price if changing*	PY27	*previous price if changing*	PY27	*previous price if changing*	PY27	PY27	PY27
Low voltage	Time of use		ALVT	1,709	5.1600	*4.7600*	0.0169	*0.0156*	0.0741	*0.0686*	0.1738	*0.1602*		0.3530	0.0000
		Approved solar	ALVTS	11	5.1600	*4.7600*	0.0169	*0.0156*	0.0741	*0.0686*	0.1738	*0.1602*		0.0000	0.0000
		Approved DER	ALVTD	8	5.1600	*4.7600*	0.0169	*0.0156*	0.0741	*0.0686*	0.0000	*0.1602*	0.0000	0.3530	0.0000
	Anytime (Closed to half hourly (HH) meters, except by exemption)		ALVN	2,276	5.1600	*4.7600*	0.0558	*0.0514*	0.0741	*0.0686*					0.0000
Transformer	Time of use		ATXT	1,040	5.1600	*4.7600*	0.0169	*0.0156*	0.0682	*0.0639*	0.1738	*0.1602*		0.3530	0.0000
		Approved solar	ATXTS	10	5.1600	*4.7600*	0.0169	*0.0156*	0.0682	*0.0639*	0.1738	*0.1602*		0.0000	0.0000
		Approved DER	ATXTD	5	5.1600	*4.7600*	0.0169	*0.0156*	0.0682	*0.0639*	0.0000	*0.1602*	0.0000	0.3530	0.0000
	Anytime (Closed to half hourly (HH) meters, except by exemption)		ATXN	153	5.1600	*4.7600*	0.0558	*0.0514*	0.0682	*0.0639*					0.0000
High voltage	Time of use		AHVT	149	5.1600	*4.7600*	0.0169	*0.0156*	0.0673	*0.0621*	0.1738	*0.1602*	0.8640	0.3530	0.0000
		Approved solar	AHVTS	1	5.1600	*4.7600*	0.0169	*0.0156*	0.0673	*0.0621*	0.1738	*0.1602*	0.8640	0.0000	0.0000
		Approved DER	AHVTD	6	5.1600	*4.7600*	0.0169	*0.0156*	0.0673	*0.0621*	0.0000	*0.1602*	0.0000	0.3530	0.0000
	Anytime (Closed to half hourly (HH) meters, except by exemption)		AHVN	4	5.1600	*4.7600*	0.0558	*0.0514*	0.0673	*0.0621*					0.0000
Zone substation	Time of use		AZST	9	5.1600	*4.7600*	0.0075	*0.0070*	0.1697	*0.1560*	0.0319	*0.0295*	0.8640	0.3530	0.0000
		Approved solar	AZSTS	-	5.1600	*4.7600*	0.0075	*0.0070*	0.1697	*0.1560*	0.0319	*0.0295*	0.8640	0.0000	0.0000
Sub transmission	Time of use		ASTT	-	5.1600	*4.7600*	0.0074	*0.0070*	0.1349	*0.1240*	0.0319	*0.0295*	0.8640	0.3530	0.0000
		Approved solar	ASTTS	-	5.1600	*4.7600*	0.0074	*0.0070*	0.1349	*0.1240*	0.0319	*0.0295*	0.8640	0.0000	0.0000

Note: Price Categories for commercial Solar and DER are for Vector-approved ICPs only.

Distribution line charge prices for Northern network commercial ICPs (excluding GST) 1 April 2026 *(previous price, if changing)*

					Daily FIXD $/day		Volume anytime 24UC $/kWh		Capacity CAPY $/kVA/day		Demand DAMD $/kVA/day		Excess Demand DEXA $/kVA/day	Power factor PWRF $/kVAr/day	Injection anytime INJT $/kWh
Consumer group / type	Price category type	Price category description	Price category code	Estimate ICP no (year avg. 1 April 2026)	PY27	*previous price if changing*	PY27	*previous price if changing*	PY27	*previous price if changing*	PY27	*previous price if changing*	PY27	PY27	PY27
Low voltage	Time of use		WLVH	477	14.6700	*13.5200*	0.0097	*0.0089*	0.0741	*0.0686*	0.1738	*0.1602*		0.3530	0.0000
Low voltage	Time of use	Approved solar	WLVHS	8	14.6700	*13.5200*	0.0097	*0.0089*	0.0741	*0.0686*	0.1738	*0.1602*		0.0000	0.0000
Low voltage	Time of use	Approved DER	WLVHD	1	14.6700	*13.5200*	0.0097	*0.0089*	0.0741	*0.0686*	0.0000	*0.1602*	0.0000	0.3530	0.0000
Low voltage	Anytime (Closed to half hourly (HH) meters, except by exemption)		WLVN	806	7.7900	*7.1800*	0.0329	*0.0303*	0.0741	*0.0686*					0.0000
Transformer	Time of use		WTXH	391	14.6700	*13.5200*	0.0097	*0.0089*	0.0682	*0.0639*	0.1738	*0.1602*		0.3530	0.0000
Transformer	Time of use	Approved solar	WTXHS	4	14.6700	*13.5200*	0.0097	*0.0089*	0.0682	*0.0639*	0.1738	*0.1602*		0.0000	0.0000
Transformer	Time of use	Approved DER	WTXHD	2	14.6700	*13.5200*	0.0097	*0.0089*	0.0682	*0.0639*	0.0000	*0.1602*	0.0000	0.3530	0.0000
Transformer	Anytime (Closed to half hourly (HH) meters, except by exemption)		WTXN	77	7.7900	*7.1800*	0.0329	*0.0303*	0.0682	*0.0639*					0.0000
High voltage	Time of use		WHVH	34	14.6700	*13.5200*	0.0097	*0.0089*	0.0673	*0.0621*	0.1738	*0.1602*	0.8640	0.3530	0.0000
High voltage	Time of use	Approved solar	WHVHS	-	14.6700	*13.5200*	0.0097	*0.0089*	0.0673	*0.0621*	0.1738	*0.1602*	0.8640	0.0000	0.0000
High voltage	Time of use	Approved DER	WHVHD	1	14.6700	*13.5200*	0.0097	*0.0089*	0.0673	*0.0621*	0.0000	*0.1602*	0.0000	0.3530	0.0000
High voltage	Anytime (Closed to half hourly (HH) meters, except by exemption)		WHVN	-	7.7900	*7.1800*	0.0329	*0.0303*	0.0673	*0.0621*					0.0000
Zone substation	Time of use		WZSH	3	5.1600	*4.76*	0.0075	*0.0070*	0.1697	*0.1560*	0.0319	*0.0295*	0.8640	0.3530	0.0000
Zone substation	Time of use	Approved solar	WZSHS	-	5.1600	*4.76*	0.0075	*0.0070*	0.1697	*0.1560*	0.0319	*0.0295*	0.8640	0.0000	0.0000
Sub transmission	Time of use		WSTH	3	5.1600	*4.76*	0.0074	*0.0070*	0.1349	*0.1240*	0.0319	*0.0295*	0.8640	0.3530	0.0000
Sub transmission	Time of use	Approved solar	WSTHS	-	5.1600	*4.76*	0.0074	*0.0070*	0.1349	*0.1240*	0.0319	*0.0295*	0.8640	0.0000	0.0000

Note: Price Categories for commercial Solar and DER are for Vector-approved ICPs only

GXP based line charges

Transmission line charges from 1 April 2026 *(previous price if changing)*

GXP	Connection location	Network	Vectors' annual transmission charges ($000)		$ per month for a 1/1000 of a percent share		Annual GXP volume ending Sep 2025 (MWh)		Implied volumetric rate $/kWh	
			PY27	*previous price if changing*	PY27	*previous price if changing*	PY27	*previous price if changing*	PY27	*previous price if changing*
ALB	Albany	Northern	27,739	*23,516*	23.1156	*19.5965*	983,180	*971,861*	0.0282	*0.0242*
HEN	Henderson	Northern	13,663	*11,982*	11.3855	*9.9849*	572,629	*548,587*	0.0239	*0.0218*
HEP	Hepburn Road	Auckland / Northern	19,116	*16,263*	15.9300	*13.5523*	584,652	*590,972*	0.0327	*0.0275*
HOB	Hobson St	Auckland	11,403	*10,118*	9.5026	*8.4321*	280,158	*268,628*	0.0407	*0.0377*
LFD	Lichfield	Northern	1,396	*1,136*	1.1637	*0.9465*	72,582	*65,157*	0.0192	*0.0174*
MNG	Mangere	Auckland	18,372	*15,526*	15.3096	*12.9382*	656,102	*653,947*	0.0280	*0.0237*
ROS	Mt Roskill	Auckland	20,551	*17,390*	17.1256	*14.4917*	663,279	*681,364*	0.0310	*0.0255*
OTA	Otahuhu	Auckland	8,610	*7,433*	7.1752	*6.1944*	322,696	*325,815*	0.0267	*0.0228*
PAK	Pakuranga	Auckland	18,985	*16,289*	15.8206	*13.5745*	592,848	*604,347*	0.0320	*0.027*
PEN	Penrose	Auckland	59,838	*52,078*	49.8653	*43.3979*	1,965,191	*2,038,483*	0.0304	*0.0255*
SVL	Silverdale	Northern	12,392	*10,690*	10.3264	*8.9081*	406,989	*396,075*	0.0304	*0.027*
TAK	Takanini	Auckland	15,363	*12,910*	12.8023	*10.7585*	570,640	*568,071*	0.0269	*0.0227*
WRD	Wairau Road	Northern	10,920	*9,729*	9.1003	*8.1077*	307,484	*314,322*	0.0355	*0.031*
WEL	Wellsford	Northern	5,149	*4,302*	4.2908	*3.5847*	170,854	*172,045*	0.0301	*0.025*
WIR	Wiri	Auckland	16,145	*13,772*	13.4538	*11.4765*	467,344	*468,847*	0.0345	*0.0294*
Total			259,642	*223,134*			8,616,628	*8,668,521*		

The transmission charges are passed through in bulk to the retailers and direct billed ICPs as a fixed monthly amount based on their share of the historic GXP volumes (year to September 2025) in the table above. We will also compare the historic volume share to the actual volume share (due to changes in ICPs and/or volumes through ICPs) and notify a final wash-up amount after the pricing year has finished.

Retailers determine how these transmission line charges are passed on to the consumer and retailers will be able to identify which GXP the consumer's ICP is connected to. Note that the use of volume to allocate transmission costs, leads to an implicit $ per historic kWh at each GXP.

APPENDIX 3 – TARGET REVENUE RECOVERY

Table 16: Proportion of mass market target revenue by price component

Consumer group	Customer type	Price Category type	Price Category description	Price Category Code	Fixed	Variable	Price Category Code	Fixed	Variable
				Auckland	**Daily**	**Volumetric**	**Northern**	**Daily**	**Volumetric**
Mass Market	Residential -low user	Time of use	Controlled	ARHLC	4.53%	5.73%	WRHLC	2.67%	3.16%
			DER	ARHLD	0.13%	0.14%	WRHLD	0.08%	0.07%
			Uncontrolled	ARHLU	2.19%	2.05%	WRHLU	1.42%	1.50%
		Anytime (exemption)	Controlled	ARNLC	0.20%	0.28%	WRNLC	0.09%	0.11%
			Uncontrolled	ARNLU	0.09%	0.08%	WRNLU	0.03%	0.03%
	Residential -standard	Time of use	Controlled	ARHSC	4.60%	1.38%	WRHSC	4.68%	1.50%
			DER	ARHSD	0.12%	0.04%	WRHSD	0.12%	0.04%
			Uncontrolled	ARHSU	3.37%	0.78%	WRHSU	2.71%	0.71%
		Anytime (exemption)	Controlled	ARNSC	0.38%	0.11%	WRNSC	0.18%	0.06%
			Uncontrolled	ARNSU	0.27%	0.05%	WRNSU	0.13%	0.02%
	General	Time of use	General	ABSH	2.80%	0.97%	WBSH	1.67%	0.55%
			General	ABSHD	-	-	WBSHD	-	-
		Anytime (exemption)	General	ABSN	0.43%	0.14%	WBSN	0.31%	0.07%
Unmetered		Unmetered	Unmetered	ABSU	0.23%	0.04%	WBSU	0.15%	0.03%

Table 17: Proportion of commercial target revenue by price component

Consumer group	Short description	Category	Fixed		Variable			Category	Fixed		Variable		
		Auckland	**Daily**	**Capacity**	**Volumetric**	**Demand**	**Power Factor**	**Northern**	**Daily**	**Capacity**	**Volumetric**	**Demand**	**Power Factor**
Low voltage	Time of use	ALVT	0.33%	1.23%	0.93%	0.84%	0.10%	WLVH	0.26%	0.32%	0.15%	0.25%	0.03%
		ALVTS	0.00%	0.01%	-	-	-	WLVHS	-	0.01%	-	-	-
		ALVTD	0.00%	-	-	-	-	WLVHD	-	-	-	-	-
	Non-time of use	ALVN	0.44%	0.95%	1.20%	-	-	WLVN	0.23%	0.35%	0.30%	-	-
Transformer	Time of use	ATXT	0.20%	1.97%	1.90%	1.59%	0.12%	WTXH	0.21%	0.67%	0.36%	0.59%	0.04%
		ATXTS	0.00%	0.02%	0.01%	0.01%	-	WTXHS	-	0.01%	-	0.01%	-
		ATXTD	0.00%	-	-	-	-	WTXHD	-	-	-	-	-
	Non-time of use	ATXN	0.03%	0.09%	0.12%	-	-	WTXN	0.02%	0.05%	0.05%	-	-
High voltage	Time of use	AHVT	0.03%	0.57%	0.75%	0.59%	0.04%	WHVH	0.02%	0.29%	0.19%	0.18%	-
		AHVTS	0.00%	0.01%	-	-	-	WHVHS	-	-	-	-	-
		AHVTD	0.00%	0.01%	-	-	-	WHVHD	-	-	-	-	-
	Non-time of use	AHVN	0.00%	-	-	-	-	WHVN	-	-	-	-	-
Zone substation	Time of use	AZST	0.00%	0.42%	0.17%	0.04%	0.03%	WZSH	-	0.08%	0.05%	0.01%	0.01%
		AZSTS	-	-	-	-	-	WZSHS	-	-	-	-	-
Sub-transmission	Time of use	ASTT	-	-	-	-	-	WSTH	-	0.02%	0.02%	0.01%	-
		ASTTS	-	-	-	-	-	WSTHS	-	-	-	-	-

Transmission prices will be expected to recover 26.4% of target revenue

APPENDIX 4 – CONSISTENCY WITH PRICING PRINCIPLES

The EA's Pricing Principles[33] (Pricing Principles) provide guidance on developing pricing methodologies for electricity distribution services. Vector has also had regard to the Electricity Authority's Distribution Pricing: Practice Note (Second Edition v2.2, 2022) (including the appended August 2019 practice note at pp.39–53) and the Electricity Authority's open letter to distributors dated 20 May 2024, and has considered that guidance when developing the pricing structures and processes described in this Pricing Methodology.

Consistent with that guidance, Vector's approach is to (i) use price structures and variable components to signal the economic costs of network use where practicable (for example, using time-varying peak/off-peak pricing and controlled/DER-enabled options to better align prices with peak network conditions and the value of flexibility), and (ii) recover the remaining shared and largely sunk costs primarily through fixed charges to minimise distortion of consumption and investment decisions.

Vector also applies a structured cost allocation and review process consistent with the practice note's guidance on assessing pricing outcomes at a consumer group level (including subsidy-free considerations and the use of consumer groupings as a practical unit of analysis). Vector uses its Cost of Service Model (COSM) to allocate target revenue to consumer groups using relevant cost drivers, and then tests forecast revenue from prices against those allocations, while also having regard to customer aspects such as affordability, predictability, bill stability and equity.

In respect of the practice note's guidance on responsiveness and negotiation, Vector provides for non-standard pricing arrangements where appropriate (including to reflect atypical circumstances and to enable price/quality trade-offs), alongside standard tariff structures that differentiate service characteristics (for example controlled load and DER options).

Finally, consistent with the practice note's emphasis on transparency and practicable implementation (including assignment/transition considerations and transaction costs), Vector's pricing approach applies time-varying tariffs by default where TOU metering exists, with limited exemptions, and includes defined control schedule arrangements for controllable load.

Table 18 demonstrates the extent to which the Pricing Methodology is consistent with the Pricing Principles.

[33] Available at https://www.ea.govt.nz/industry/distribution/distribution-pricing/

Table 18 Pricing principles

<u>Principle (a): Economic costs of service provision</u> *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);* *ii. reflecting the impacts of network use on economic costs;* *iii. reflecting differences in network service provided to (or by) consumers; and,* *iv. encouraging efficient network alternatives.*
<u>Being subsidy free</u> The avoidable cost test can be applied for both individual ICPs and for groups of ICPs (consumer groups). The avoidable cost for an individual ICP is the cost of connecting that ICP to the network and the cost of consumption at peak times. Avoidable costs therefore exclude residual costs. The avoidable cost for a group of ICPs is the cost of connecting that group of ICPs to the network, the costs of that groups consumption a peak times and includes the cost of assets shared by that group. Applying the avoidable cost test at a group level is more stringent because it includes shared costs for the group. Revenues for the group must be higher than just the sum of the avoidable cost for each individual ICP as revenues must also cover shared costs. Our connection pricing methodology ensures that individual ICPs generally pay the costs of connecting to the network plus a contribution to the shared capital expenditure necessary for the long-term growth of the network. Our network variable usage charges reflect the cost of consumption at peak times and our fixed charges reflect shared (residual) cost recovery. The standalone cost can be considered as the costs from the lowest cost viable alternative. While we monitor the cost of a range of alternative options for ICPs, it can be difficult to apply these on an ICP specific basis. In some instances, the economic value of the service, including where that is set by the cost of an alternative form of supply, may be notified to us by the consumer or their retailer. In these situations, this pricing principle is delivered through the operation of pricing principle (c), detailed below. *<u>Reflecting the impacts of network use on economic costs</u>* Our variable prices aim to reflect long run marginal cost, signalling the additional cost caused by one more unit of network use at a given time. In time periods when the network is unconstrained, the marginal cost of extra use is low, so prices reflect that, when the network is congested, marginal costs are higher and prices aim to reflect that higher cost. Fixed charges are set with the aim of recovering residual costs efficiently. Costs that do not vary with usage (e.g. sunk or shared costs) are recovered through fixed charges. These are set to minimise distortions to efficient consumption and investment, while being mindful of participation constraints.

Our target revenue allocation, described in this document, illustrates how we utilise relevant cost drivers to allocate costs to various consumer groups. We test the forecasted revenue from prices against this cost allocation to ensure that revenues collected through prices are broadly in line with costs. We also consider other aspects such as affordability, predictability, bill stability and equity.

Reflecting differences in network service provided to (or by) consumers

Our prices reflect the services provided. Peak and off-peak pricing reflects the congestion costs of providing the service at those times. Connections that have elements of control have prices that reflect the benefit the network derives from that flexibility. Much of the network costs are sunk and therefore unavoidable, fixed prices reflect this. Injection provides benefit to the network so injection pricing reflects this. Connections are at different levels on the network and therefore prices aim to reflect how deep or shallow the connection is on the network.

Encouraging efficient network alternatives

We offer distributed energy resources tariffs to residential and commercial connections in return for the ability to require management of their load (e.g. hot water and electric vehicle charges) against a dynamic or non-dynamic operating envelope we provide. This pricing approach signals the benefits to consumers, retailers and third parties of responding to our load management signals. These pricing options, also encourage investments in non-traditional network alternatives, and therefore reduce the need for future investment costs in traditional network assets.

Our cost reflective price signals provide incentives for demand management to shift load from peak to off-peak times, they also encourage efficient network alternatives such as distributed generation and battery storage usage at peak times.

Principle (b): Recovery of any shortfall

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

As variable prices aim to recover marginal costs, and fixed prices aim to recover residual costs it is not expected there would be under recovery. Residual cost recovery being done via fixed pricing ensures prices do not distort network usage or investment decisions. Also, the Commission’s regulatory settings include a wash-up mechanism which permits over / under recovery of revenues in one period to be recovered in future periods.

Principle (c): Responsive to requirements of consumers

Prices should be responsive to the requirements and circumstances of end users by allowing negotiation to:
i. reflect the economic value of services;
ii. enable price/quality trade-offs.

Reflect the economic value of services

We offer non-standard pricing in certain circumstances including where standard pricing would cause uneconomic bypass of the network.

Non-standard contractual arrangements are also able to address changes to the structure or level of prices (e.g. for atypical load patterns, or to address particular by-pass or fuel substitute situations), and differing service levels (e.g. a higher level of redundancy, or priority response if an outage occurs). The Pricing Methodology sets out how we take account of these issues when considering the design of a non-standard contract.

Where the connection of new load requires investment in the network (e.g. new subdivisions) then the cost of that investment is recovered via connection charges and/or non-standard prices. Those prices provide the economic incentive for distribution alternatives to be investigated by the proponent of the development. For example, a new subdivision that adopts new technologies to reduce load will not require the same level of network investment.

Enable price/quality trade-offs

We offer price/quality trade-offs. Through our controlled/DER/uncontrolled pricing, we reward consumers, if passed on by the retailers, the benefit of accepting the potential interruption of hot water supply or control of their smart load. Through our TOU prices, we reward consumers, if passed on by the retailers, a benefit if they are willing to shift their usage out of peak periods.

Principle (d): Pricing process

Development of prices should be transparent and have regards to transaction costs, consumer impacts, and uptake incentives.

We believe that as we evolve our pricing to be more cost reflective that pricing structures will become more complex and transparency more difficult. However we will always be transparent in why we are making those changes. Presently pricing structures are relatively simple as cost reflectivity is signalled at a fairly high level e.g. peak is signalled at a network wide level. Therefore, costs are clearly identified and allocated to consumer groups on a simple and transparent basis. As pricing moves to a more granular level both spatially and temporally to better signal congestion and the value of avoiding that congestion then transparency will become more challenging. That said the reasons and justification for those changes will still be consulted on, made clear, be compliant with regulations and consistent with regulatory guidance.

For example our decision to move and make mandatory mass market two-part time of use, followed extensive modelling of consumer effects for a range of potential pricing structures that considered the consumer impacts and incentives. We consulted with stakeholders, including retailers and Entrust, and obtained consumer insights through application of detailed data analytics in the development of these prices and will continue to consult going forward.

The information we receive from stakeholders and customers helps us to understand consumer drivers and preferences. We have undertaken a range of trials and will continue to do so, in order for us to anticipate and respond to consumer's requirements as technology and the move to net zero changes the future of energy.

We formally consult with retailers and Entrust on our proposed price changes each year. Informally throughout the year we engage with multiple stakeholders including energy retailers to explore options to better shape prices to drive long term benefits for end consumers.

We offer the same network pricing to all ICPs irrespective of which retailer they use.

We expect to continue to evolve our pricing as consumer's respond to the range of choices they have through technological innovation and increasing electrification, and regulatory reforms.

In addition to the EA's Pricing Principles, Vector has considered the Electricity Authority's open letter to distributors dated 20 May 2024 on distribution pricing reform, which sets out five focus areas the Authority will consider when assessing pricing methodologies (for pricing years from 2025/26 onwards). These focus areas are: allocating revenue transparently; assigning ICPs to time-varying distribution tariffs (limited exceptions only); setting peak rates based on a measure LRMC; reducing off-peak and controlled rates; and following up on Asset Management Plan (AMP) reporting on readiness for increased electrification.

Vector's alignment with these focus areas is reflected in both the design of our pricing methodology and the way we evolve and communicate pricing over time (including through our roadmap and annual consultation and governance processes). In particular, Vector engages with key stakeholders during price setting (including retailers and Entrust) and has briefed the EA as part of our PY27 process. Table 19 demonstrates the extent to which the Pricing Methodology is consistent with the focus areas.

Table 19 Open letter focus area and alignment

EA open letter focus area (20 May 2024)	Vector alignment summary
Allocate revenue transparently	Vector's methodology outlines a cost allocation framework using a cost of service / classification of service model approach (COSM) to support transparency on allocation methods and how revenue is recovered.
Assign all ICPs to time-varying distribution tariffs (limited exceptions only)	Vector applies TOU tariffs to metered mass-market connections by default, with limited exceptions where metering is inadequate; and applies TOU across commercial customers where half-hourly requirements/data apply.
Set peak rates based on a measure of LRMC	Vector sets TOU peak rates using LRMC-based inputs and targeted peak hours to better align peak signals with network investment costs.
Reduce off-peak and controlled rates	Consistent with the open letter's guidance that off-peak LRMC is typically near zero and that residential off-peak/controlled charges should move toward zero, Vector's approach includes very low/zero off-peak pricing settings and ongoing refinement of controlled/DER-enabled options to encourage flexible load. Vector monitors responses to peak/off-peak signals and has refined peak period definitions to better reflect network constraints (e.g., extending peak hours).
Follow up on AMP reporting on readiness for increased electrification	Vector's pricing methodology is developed having regard to our AMP and readiness for increased electrification, including how pricing and flexibility options support efficient network utilisation as demand grows (e.g., revised residential DER eligibility to include EV chargers)

APPENDIX 5 – COMPLIANCE REFERENCE

Table 20 Disclosure requirements from the ID determination and relevant definitions if applicable from Input Methodologies

Determination clause	Requirement	Section of this document
Disclosure of pricing methodologies **2.4.1**	Every EDB must publicly disclose, before the start of each disclosure year, a pricing methodology which- (1) Describes the methodology, in accordance with clause 2.4.3, used to calculate the prices payable or to be payable; (2) Describes any changes in prices and target revenues; (3) Explains, in accordance with clause 2.4.5, the approach taken with respect to pricing in non-standard contracts and distributed generation (if any); (4) Explains whether, and if so how, the EDB has sought the views of consumers, including their expectations in terms of price and quality, and reflected those views in calculating the prices payable or to be payable. If the EDB has not sought the views of consumers, the reasons for not doing so must be disclosed.	Price setting compliance Price changes Target revenue and its categorisation Transmission pass-through pricing CONSULTATION, DISCUSSION, GOVERNANCE, & COMPLIANCE TIMEFRAME Non-standard contracts & distributed generation policies
2.4.2	Any change in the pricing methodology or adoption of a different pricing methodology, must be publicly disclosed at least 20 working days before prices determined in accordance with the change or the different pricing methodology take effect	This methodology will be disclosed within 20 days of the new prices taking effect.

2.4.3	(1) Include sufficient information and commentary to enable interested persons to understand how prices were set for each consumer group, including the assumptions and statistics used to determine prices for each consumer group; (2) Demonstrate the extent to which the pricing methodology is consistent with the pricing principles and explain the reasons for any inconsistency between the pricing methodology and the pricing principles; (3) State the target revenue expected to be collected for the disclosure year to which the pricing methodology applies; (4) Where applicable, identify the key components of target revenue required to cover the costs and return on investment associated with the EDB's provision of electricity lines services. Disclosure must include the numerical value of each of the components; (5) State the consumer groups for whom prices have been set, and describe- (a) the rationale for grouping consumers in this way; (b) the method and the criteria used by the EDB to allocate consumers to each of the consumer groups; (6) If prices have changed from prices disclosed for the immediately preceding disclosure year, explain the reasons for changes, and quantify the difference in respect of each of those reasons; (7) Where applicable, describe the method used by the EDB to allocate the target revenue among consumer groups, including the numerical values of the target revenue allocated to each consumer group, and the rationale for allocating it in this way; (8) State the proportion of target revenue (if applicable) that is collected through each price component as publicly disclosed under clause 2.4.18.	Consumer groups Price changes & price setting compliance Appendix 4 – consistency with pricing principles Target revenue and its categorisation Price changes & price setting compliance Price changes & updated criteria Distribution target revenue allocation & price comparison
2.4.4	Every disclosure under clause 2.4.1 must, if the EDB has a pricing strategy- (1) Explain the pricing strategy for the next 5 disclosure years (or as close to 5 years as the pricing strategy allows), including the current disclosure year for which prices are set; (2) Explain how and why prices for each consumer group are expected to change as a result of the pricing strategy; (3) If the pricing strategy has changed from the preceding disclosure year, identify the changes and explain the reasons for the changes.	N/A

2.4.5	Every disclosure under clause 2.4.1 must- (1) Describe the approach to setting prices for non-standard contracts, including- - (a) the extent of non-standard contract use, including the number of ICPs represented by non-standard contracts and the value of target revenue expected to be collected from consumers subject to non-standard contracts; (b) how the EDB determines whether to use a non-standard contract, including any criteria used; (c) any specific criteria or methodology used for determining prices for consumers subject to non-standard contracts and the extent to which these criteria or that methodology are consistent with the pricing principles; (2) Describe the EDB's obligations and responsibilities (if any) to consumers subject to non-standard contracts in the event that the supply of electricity lines services to the consumer is interrupted. This description must explain- (a) the extent of the differences in the relevant terms between standard contracts and non-standard contracts; (b) any implications of this approach for determining prices for consumers subject to non-standard contracts; (3) Describe the EDB's approach to developing prices for electricity distribution services provided to consumers that own distributed generation, including any payments made by the EDB to the owner of any distributed generation, and including the- (a) prices; and (b) value, structure and rationale for any payments to the owner of the distributed generation.	Non-standard contracts & distributed generation policies Distribution target revenue allocation & price comparison
2.9.1	Where an EDB is required to publicly disclose any information under clauses 2.4.1, 2.6.1, 2.6.3, 2.6.6 and 2.7.2, the EDB must at that time publicly disclose a certificate in the form set out in Schedule 17 in respect of that information, duly signed by 2 directors of the EDB.	Appendix 6 – director's certification
Disclosure of prices **2.4.18**	Every EDB must at all times publicly disclose— (1) Each current price expressed in a manner that enables consumers to determine- (a) the consumer group or consumer groups applicable to them; (b) the total price for electricity lines services applicable to them; (c) the prices represented by each price component applicable to them; and	Appendix 2 - line charge prices from 1 April 2026

	(d) the amount of each current price that is attributable to transmission charges; (2) The number (or estimated number) of consumers which must pay each price; (3) The date at which each price was or will be first introduced; and (4) The price that was payable immediately before each current price (if any) expressed in the manner referred to in subclause (1).	
2.4.19	Every EDB must, at least 20 working days before changing or withdrawing a price or introducing a new price that is payable by 5 or more consumers- (1) Publicly disclose- (a) the information specified in clause 2.4.18 in respect of that price; and (b) an explanation of the reasons for the new price or the changed or withdrawn price; (2) In addition, either- (a) give written notice to each consumer by whom that price is, or in the case of a withdrawn price would have been, payable, including the information specified in clause 2.4.18 in respect of that price; or (b) notify consumers in the news section of either- (i) 2 separate editions of each newspaper; or (ii) news media accessible using the internet that is widely read by consumers connected to EDB's network; (c) notification under subclause (2)(b) must provide details of the price, including- (i) the changed price alongside the immediately preceding price applicable; and (ii) contact details where further details of the new or changed price can be found including the URL of the EDB's publicly accessible website.	Publication of the pricing methodology in New Zealand Herald and NZ Stuff by 2 March 2026
2.4.20	Every EDB must, in respect of- (1) All new prices payable; or (2) In the case of withdrawn prices, the prices which would have been payable; by 4 or fewer consumers, at least 20 working days before introducing a new price, give written notice to each consumer by whom that price is payable, the information specified in clause 2.4.18 in respect of that price.	Publication of the pricing methodology in New Zealand Herald and NZ Stuff by 2 March 2026
Input Methodologies **3.1.1 (7)**	'Prices' means- (a) individual tariffs, fees or charges; or (b) individual components thereof, in nominal terms exclusive of GST for the supply of an electricity distribution service, and must include a discount taken up by consumers.	

APPENDIX 6 – DIRECTORS' CERTIFICATION

Schedule 17: Certification for Pricing Methodology Disclosure

Clause 2.9.1

We, Doug McKay and Bruce Turner, being directors of Vector Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

(a) The following attached information of Vector Limited prepared for the purposes of clauses 2.4.1 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

(b) 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.

____
Director

____
Director

19 February 2026
____
Date