Electricity Pricing Methodology

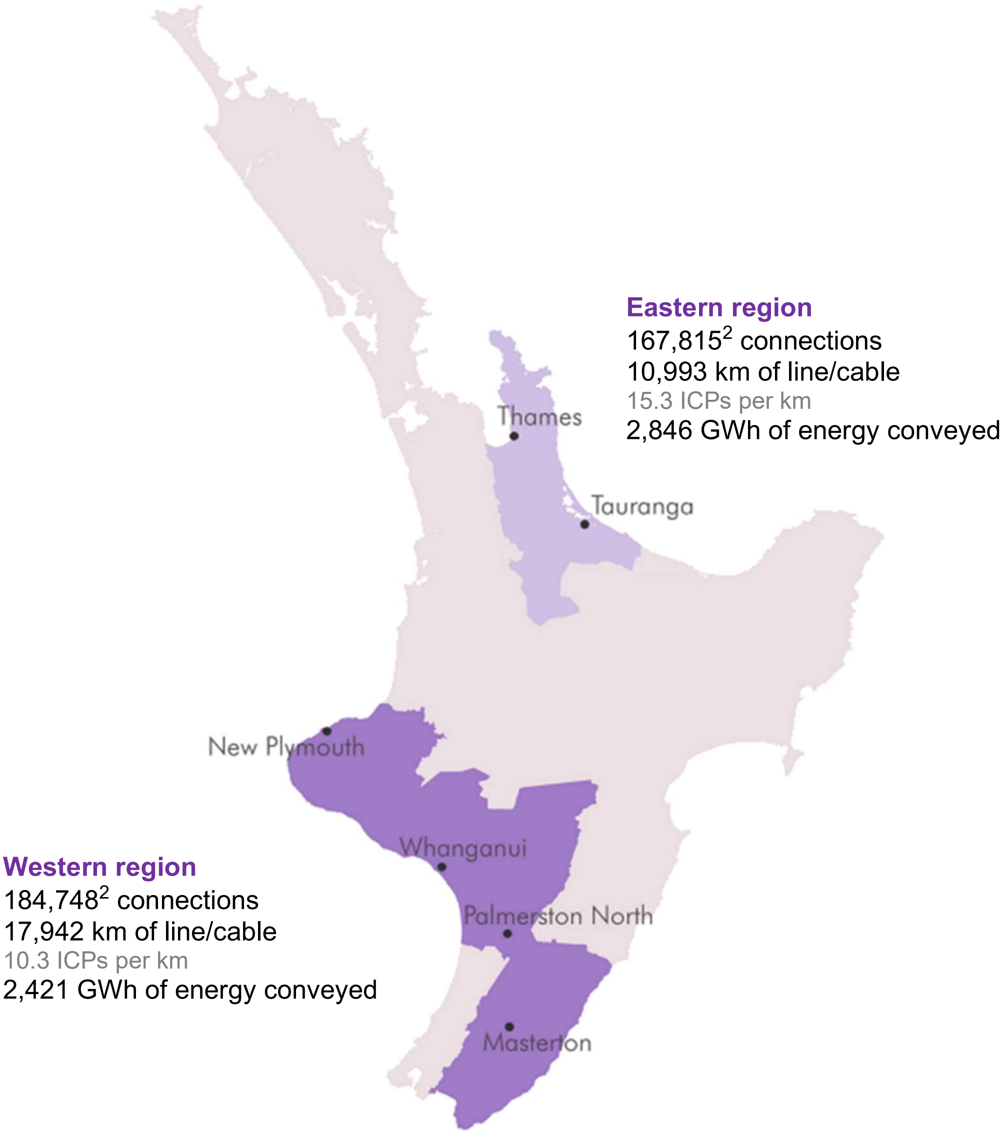
April 2023 – March 2024

POWERCO

1. ABOUT POWERCO

Powerco's electricity network supplies electricity to about 350,000 customer connections across two regions of the North Island. In terms of both supply area and network length, our network is the largest of any single distributor in New Zealand. The two network regions are referred to as Eastern (Valley and Tauranga) and Western (Taranaki, Whanganui, Manawatu and Wairarapa). Both regions contain a mix of urban and rural areas.

Figure 1: Powerco's Eastern and Western network regions and key statistics[1]



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[1] As at 31 March 2022.

[2] Number of connections differs from ICP counts, because inactive ICPs are included.

2. HELPING YOU UNDERSTAND HOW WE SET ELECTRICITY PRICES

The purpose of this document is to help you understand how Powerco sets prices for its electricity distribution services. It demonstrates how our electricity pricing methodology (our approach) is used to set prices to reflect the costs of supplying distribution services in an efficient and fair way.

- Section 2 (this section): Helping you understand how we set electricity prices
- Section 3: How we group customers
- Section 4: How prices are set for each customer group
- Section 5: Current pricing approach and plans to evolve our pricing
- Section 6: Changes to our pricing approach and prices in FY24
- Section 7: Calculating and allocating costs across customer groups
- Section 8: Assessing customer impacts
- Section 9: Alignment with Electricity Authority Pricing Principles
- Section 10: How we meet the Commerce Commission Information Disclosure requirements

WE SET PRICES TO REFLECT COSTS AND HELP CUSTOMERS MAKE DECISIONS ABOUT USING OUR NETWORK

We set prices to reflect the costs of supplying electricity distribution services to each customer or group of customers connected to our network. For most customers, our prices are part of several components of a retail bill. Retailers package our prices in different ways, which can make it difficult to distinguish them within a retail bill.

The distribution services we supply are:

- Connecting customers to our network
- Transferring electricity to and from connections via our network's assets
- Upgrading/downgrading capacity for existing customers that want to take or inject more/less electricity than they currently do.

The Commerce Commission regulates and sets the revenue (which sets the 'cost') we can recover through our prices in each year. These regulations also require us to include other costs in our prices, such as transmission prices and regulatory levies.

Our approach to setting prices can inform customer decisions about connecting to, and using, our network by signalling the cost of supply. These costs are affected by a range of factors influencing the network infrastructure required to supply the distribution service. We want our prices to reflect these costs so we can plan and operate our network assets efficiently, reliably, and safely.

We review our pricing approach annually (at a minimum), so prices give customers the best possible information about the costs of supplying them. This is increasingly important as customers and their agents use our network in new ways by adopting technology and services like solar panels, electric vehicles, electric heating and cooling, and energy management systems.

FACTORS WHICH INFLUENCE OUR PRICING APPROACH AND PRICES

The factors which influence our pricing approach and pricing can be grouped into three areas:

- **Customer characteristics** including consumption patterns at different locations, uptake of solar panels, electric vehicles, energy efficient devices
- **Network characteristics** including topography, growth, system reliability and security, customer density, network use, data availability
- **Regulatory requirements** for example requirements imposed by legislation about the structure and level of prices

Customer characteristics

Customer characteristics such as load profiles and connection type affect the cost of supplying the distribution service. Our pricing approach considers the following characteristics:

- **Load profiles**: Your electricity consumption can vary across the day and year for a range of reasons, eg weather or lifestyle. We allocate costs based on consumption profiles because it is the most important driver of fixed cost investment in network infrastructure.
- **Connection type / network use / capacity requirements**: A higher capacity connection typically requires more assets and therefore higher fixed costs. For example, a new dairy connection may need a dedicated transformer which cannot be utilised by other customers. We allocate these costs directly where/when possible, reflecting the dedicated nature of these assets.
- **Location**: Customers in the Eastern and Western regions are supplied using separate networks with their own cost characteristics. Another key factor is the relevant Grid Exit Point connecting our network to the national transmission grid, because this impacts Transpower’s charges, which we reflect in our prices.
- **Density**: Customer density[3] varies across the network and impacts on cost allocation. For example, the cost of supplying distribution services can be higher in lower density areas (typically rural areas) because the costs are shared across fewer customers.
- **Emerging customer preferences and technology choices**: Customer uptake of new technology offerings such as solar panels and battery storage is changing the way energy markets operate. Distributors play a key role in facilitating these changes. We aim to keep our prices technology-neutral, so the pricing is aligned with the impact on network costs.

[3] A measure of customer density is the number of customers per km of network length.

Network characteristics

Powerco operates over 28,000 km of electricity distribution network across the North Island of New Zealand. Our network is split into two regions, with the Eastern region covering Tauranga and Thames Valley and the Western region spanning across Taranaki, Whanganui, Manawatu, and the Wairarapa. These regions contain a range of urban and rural areas. Differences in the network requirements, population and load characteristics mean the cost of supply varies between and within our network regions.

Table 1: Network Characteristics as Described in our Asset Management Plan

Region	Pricing Zone	GXP(s)	Regional Description	Network Considerations
Valley	VALLEY	Arapuni (ARI1101) Hinuera (HIN0331) Kinleith (KIN0331 & KIN0112) Kopu (KPU0661) Piako (PAO1101) Waihou (WHU0331) Waikino (WKO0331)	Valley includes a diverse range of terrain, from the rugged and steep forested coastal peninsula of Coromandel to the plains and rolling country of eastern and southern Waikato. Economic activity in these areas is dominated by tourism and farming respectively. From a planning perspective, this region presents significant challenges in terms of maintaining reliability on feeders supplying sparsely populated areas in what is often remote, difficult-to-access terrain. Investment priorities have focused on improving network security and resilience, and developing better remote control and monitoring facilities.	• Mostly favourable terrain for network construction and maintenance, with rather temperate weather. • Lower population density overall, when compared to the Tauranga region. • Coromandel (Kopu GXP) and Waikino are characterised by more rugged terrain with less adequate roads for heavy vehicles. • Seasonal fluctuations in population in the Coromandel cause holiday period peaks at certain zone substations. • The rest of the Valley's demands are more influenced by commercial and industrial sites and permanent residents. • Kinleith's demand is dominated by the pulp and paper plant located there, Powerco's largest industrial customer.
Tauranga	TAURANGA	Tauranga (TGA0111 & TGA0331) Mt Maunganui (MTM0331) Te Matai (TMI0331) Kaitemako (KMO0331)	Tauranga is a rapidly developing coastal region, with horticultural industries, a port and a large regional centre at Tauranga. The principal investment activities in this zone have been associated with accommodating the rapid urban growth in Tauranga, maintaining safe and reliable supplies to the port, supplying new businesses, and supporting the horticultural industry.	• Steady population and demand growth in Tauranga and Mt Maunganui, which seems likely to continue. • Growth is expected in both the horticultural and residential sectors. • Exposure along the coast indicates future costs for the maintenance and replacement of deteriorating assets.

Region	Pricing Zone	GXP(s)	Regional Description	Network Considerations
Manawatu	A	Bunnythorpe (BPE0331) Linton (LTN0331)	Manawatu includes rural plains and high country areas exposed to prevailing westerly winds. It is mainly agricultural in nature, but the large regional centre of Palmerston North has significant logistical industries, a university, and associated research facilities.	• The urban centre of Palmerston North is expected to have continued growth, while growth in the more rural Tararua area is expected to remain flat. • While windy weather is common, this is more of an issue in the more rugged and less accessible Tararua (Mangamaire GXP) area.
	B	Mangamaire (MGM0331)		
Taranaki	A	Carrington (CST0331) Huirangi (HUI0331) Stratford (SFD0331)	Taranaki, which is situated on the west coast plains, is exposed to high winds and rain. The area, which includes the large regional centre of New Plymouth, has significant agricultural activity, oil and gas production, and some heavy industry.	• Chances of extreme weather and corrosion of assets from exposure along the coastline. • Population density varies considerably within the Taranaki region. • Growth in the region is heavily influenced by the agricultural, gas and oil industries.
	B	Hawera (HWA0331) Opunake (OPK0331)		
Whanganui	A	Brunswick (BRK0331) Wanganui (WGN0331)	Whanganui includes the surrounding Rangitikei and is a rural area exposed to westerly sea winds on the coast and snowstorms in high country areas. It is predominantly agriculture-based with some industry.	• The rural areas of the Whanganui region are rugged and hilly. Flooding of the Whanganui River can occur. • Whanganui itself is experiencing growth which seems likely to continue. • The Ruapehu district is subject to extreme weather conditions and snowfall. Ohakune's population and demands are very seasonal, as a popular winter destination.
	B	Marton (MTN0331) Mataroa (MTR0331) Ohakune (OKN0111) Waverley (WVY0111)		
Wairarapa	B	Greytown (GYT0331) Masterton (MST0331)	Wairarapa is more sheltered and is predominantly plains and hill country. It has a mixture of agricultural, horticultural and viticulture industries.	• Carterton and Greytown are growing and are expected to grow further. • Weather can be extreme in coastal areas and flooding can occur.

More detail of our investment plans and day-to-day asset management priorities across out network regions is in our Asset Management Plan, available at https://www.powerco.co.nz/who-we-are/pricing-and-disclosures/electricity-disclosures

Regulatory requirements

Our pricing approach is influenced by a range of regulatory requirements from Government, the Commerce Commission, and the Electricity Authority. The main obligations are:

- Setting prices to recover the allowable revenue the Commerce Commission approved for Powerco so we can invest in our network to improve reliability and quality of supply. **Sections 3, 4 and 7** describe how we do this.
- Setting prices for distributed generation connected to and using our network according to Part 6 of the Electricity Industry Participation Code 2010, relating to the pricing of distributed generation. **Section 4**, and our Distributed Generation Policy, describe how we do this.
- Setting efficient and cost-reflective prices consistent with the Electricity Authority's Distribution Pricing Principles of August 2019[4]. **Section 9** describes how our pricing approach aligns with these.
- Disclosing information about our pricing approach, and price–setting for the year ahead under the Commerce Commission's Electricity Distribution Information Disclosure[5] requirements. **Section 10** describes how we meet these, along with information on our website at: https://www.powerco.co.nz/who-we-are/pricing-and-disclosures.
- We are required to offer household customers a low fixed charge tariff option (of 45 cents/day) by the *Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004* (the "Low Fixed Charge Regulations"). The Electricity Authority monitors and enforces the regulations. The Low Fixed Charge Regulations prevent us from setting prices which reflect the cost of supply.

OTHER SOURCES OF PRICING INFORMATION

Other sources of pricing information are available on our website.

- Information for customers connecting distributed generation to our network about the connection process, connection charges and our approach to procuring distributed generation for network alternatives, is available in our Distributed Generation Policy here
- Information for commercial and industrial customers about new connections and upgrades is available here
- Technical information for retailers on our pricing is available in our Pricing Policy here
- Information for customers about our annual price and revenue changes is available in our Annual Price-Setting Compliance Statements here
- Information about pricing changes from 1 April 2023 is available in our Reasons for Change factsheet here

[4] The Electricity Authority Pricing Principles are available at: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/distribution-pricing-review/development/summary-of-submissions-and-decision-paper/
[5] The Commerce Commission Information Disclosure requirements are available at https://comcom.govt.nz/regulated-industries/electricity-lines/information-disclosure-requirements-for-electricity-distributors

3. HOW WE GROUP CUSTOMERS

Prices are set for specific customer groups because it is not practical to set individual prices, except for large commercial and industrial customers. A key step of the pricing approach is grouping connections across each network, based on location and connection size or capacity. These criteria reflect the influence on costs of network and customer characteristics such as geography, rural/urban network density, mains size, protection rating and/or transformer capacity.

We use seven groups of connections for the Eastern region and four groups for the Western region. The table below describes each group.

Table 2: Customer groups used for the Eastern and Western regions

Eastern region	Western region
T01/T02 and V01/V02 – for **all unmetered connections** such as streetlights in the Valley and Tauranga regions The unmetered nature of the load and the associated dedicated equipment, require special consideration when allocating costs T05S/T06S and V05S/V06S – for **all residential customers and small commercial customers** with a fuse size of 3 Phase 60 Amps or less Any customers with a fuse size of up to 3 Phase 60 Amps are typically considered to be residential or small commercial customers and, as such, individually place minimal demands on our network and require minimal investment in on-site and upstream assets Providing specific eligibility criteria[6] are met, residential customers can choose between the low user price categories (V05S/T05S) and the standard price categories (V06S/T06S) V08 – for **connections that are classified as temporary accommodation**, with an installed capacity of 15kVA or less, and supplied from Kopu GXP[7]	E1 – for all **residential and most commercial customers including unmetered connections** All connections with a connected capacity of up to 100 kVA which represents all residential and most commercial customers The E1 price category has been limited to less than 100 kVA to provide a relatively simple price structure for most customers while excluding all connections which require dedicated on-site and/or upstream assets
T22/V22 – for **medium commercial customers** with a fuse size of greater than 3 Phase 60 Amps up to and including 3 Phase 250 Amps Any connections with these fuse sizes are typically commercial customers with higher average volumes than the T05S/T06S and V05S/V06S price categories. Therefore, this group places increased demands on different components of our network and requires a slightly larger investment in on-site and upstream assets	E100 – for **medium commercial customers** with an installed capacity of 101 – 300 kVA. These equate to medium-large commercial customers. This price category has been defined because connections with this level of capacity

[6] For details on the eligibility criteria for the low user (also known as low fixed charge) prices, please see the full Pricing Policy here.
[7] For details on the eligibility criteria for the Temporary Accommodation (V08) prices please see the full Pricing Policy here.

<table>
<tr><th>Eastern region</th><th>Western region</th></tr>
<tr><td>T28/V28 – for medium commercial customers with an installed capacity of 200 – 299 kVA

Any connections with this level of installed capacity are typically medium sized commercial customers with significantly higher average volumes than the T22/V22 price categories. Therefore, this group places increased demands on the upstream network assets and requires a slightly larger investment in on-site and upstream assets</td><td>place different levels of demand on different components of our network assets such as sub-transmission, high voltage (11kV) and low voltage (400V) assets and typically require dedicated on-site assets such as transformers and associated switchgear</td></tr>
<tr><td>T50/V40 – for large commercial customers with an installed capacity of 300 – 1499 kVA</td><td>W50 – for large commercial customers with an installed capacity of 301 – 1499 kVA.</td></tr>
<tr><td colspan="2">Any connections with this level of installed capacity are typically large commercial customers which require dedicated transformers and associated switch gear to meet their supply requirements</td></tr>
<tr><td>T60/V60 – for large commercial customers with an installed capacity of 1,500 kVA and greater</td><td>SPECIAL – for large commercial customers with an installed capacity of 1,500 kVA and greater</td></tr>
<tr><td colspan="2">Any connections with this level of installed capacity are typically very large commercial/industrial customers who place increased demand on upstream network assets and require dedicated on-site transformers and dedicated feeders to meet their supply requirements

Because connections in the V40, T50, W50, T60, V60 and SPECIAL price categories typically require dedicated on-site and, in some cases, upstream assets, they are all individually priced based on their specific on-site and upstream assets and contribution to peak demands. While these customers are charged a constant daily price, it is reviewed each year based on the customer’s previous year’s peak demands (as detailed in Section 4) and any changes to the relevant assets in the current year. This ensures that their prices are regularly updated to reflect their individual contribution to network costs</td></tr>
</table>

Customers are assigned to a group based on the location of the GXP that is associated with their connection, and on the installed capacity of their connection. More detail on the location and capacity criteria is provided below.

The granularity of the groupings for each category reflects a trade-off between practicality, fairness, and cost-reflectiveness. We have made several incremental improvements over recent years to simplify our price structure, while maintaining or increasing fairness and limiting price impacts on customers.

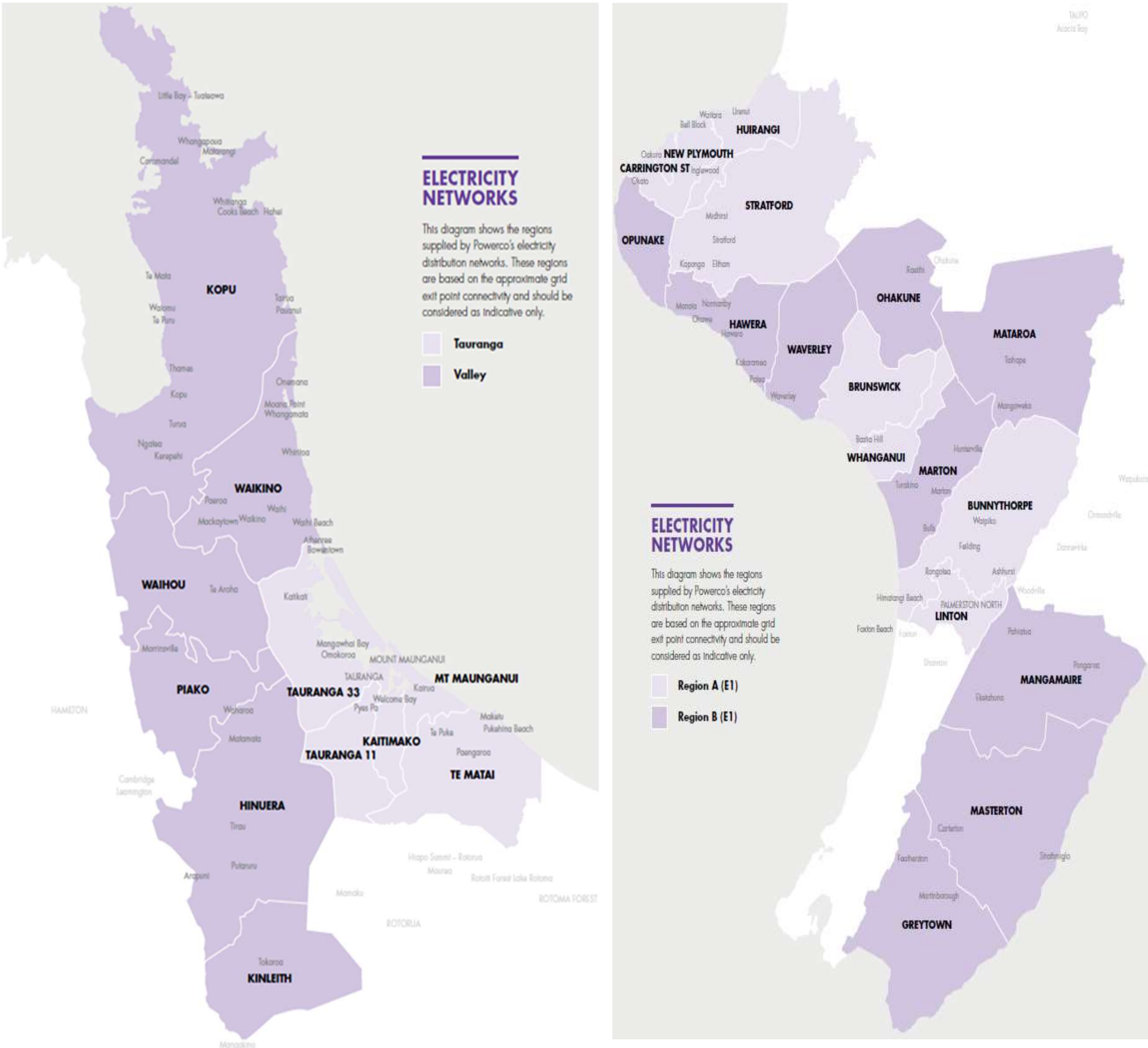
We use different Eastern and Western customer groups partly for historical reasons, but mainly reflecting different billing methodologies. The main difference is more capacity bands for customers in the Eastern region, which allows prices to reflect costs more closely for each customer group, although the Western region has more granularity in its sub-regions. We will reassess the number of customer groups in the Western region as part of a transition to ICP pricing.

How location is factored into pricing

The location criteria reflect the underlying cost of supplying distribution services to customers in specific locations. The following figure shows the pricing zones for the Eastern and Western regions. Grouping customers by location assists in recognising the relative costs of supplying customers within specific areas and allows a fairer allocation of costs.

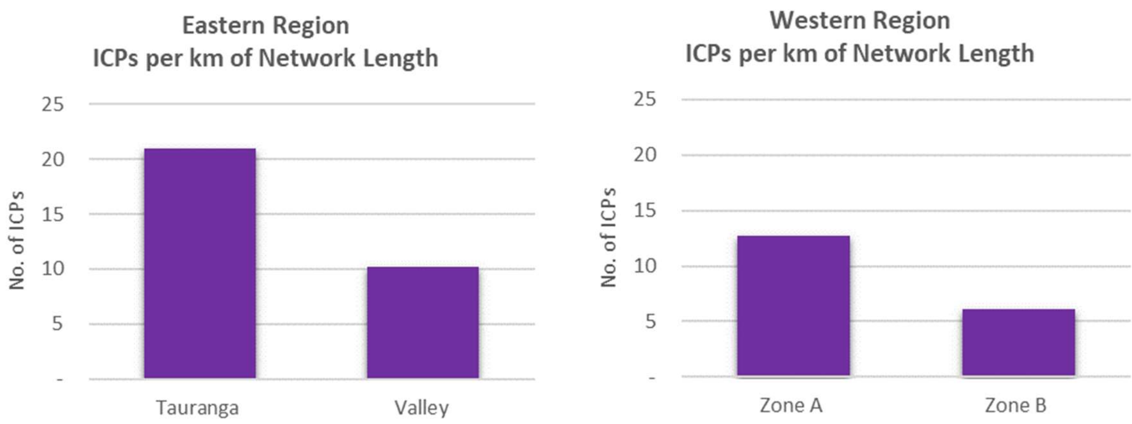
Figure 2: Eastern and Western region pricing zones

Eastern region | **Western region**



The Eastern and Western regions are each split into two zones, reflecting customer density within each region (see below).

Figure 3: Average network density (Eastern and Western regions)



Eastern region

Customers are grouped based on connection to either the Tauranga or Thames Valley sub-regions. The Tauranga part of the network has a higher density than Thames Valley. Prices for residential customers on the Valley network are typically higher than in the Tauranga network because the lower network density and greater average system length means the costs of supply are allocated across fewer customers.

Western region

Customers are grouped by GXPs which have a similar network density:

- Zone A includes customers connected to GXPs supplying the high-density urban centres of New Plymouth, Whanganui, and Palmerston North
- Zone B includes customers connected to GXPs supplying the remaining low density and typically rural areas

For residential and small commercial customers, prices for zone B are typically higher than zone A because the lower network density and greater average system length means the costs of supply are allocated across fewer customers.

Commercial and industrial customers are grouped into ten GXP zones, with each zone representing a grouping of GXPs based on geographical proximity and the structure of the network connecting them. For example, the GXPs of Huirangi, Carrington St and Stratford are grouped together into zone A. The number of zones represents Powerco’s preference for greater transparency of costs within each price category, because changes to individual customer behaviour within these groups can affect the underlying cost structure.

Capacity criteria

Customers are grouped by the capacity of their connection to the network, being either their fused capacity when connected to a shared transformer, or the size of the transformer/s dedicated to them. Capacity is used to allocate costs because it is a significant influence on network cost. Powerco's prices in the Eastern and Western regions are structured to reflect different capacity bands.

Eastern

The Eastern customer groups have similar load characteristics, such as demand, fuse size and installed capacity, as well as those which use specific sets of assets.

Fuse size is used for most Eastern customer groups because, especially for residential and smaller commercial connections, their available capacity is limited by the size of the fuses at their installation, rather than the installed capacity of dedicated transformers. For this reason, connections typically have only one applicable price category. There are situations where customer preferences and metering can determine the price category, such as the low user (V05S/T05S) and T22 price categories.

Western

The four Western region customer groups have similar characteristics relating to their installed capacity and associated demand. They reflect the use by each customer group of components of the network, such as sub-transmission, high voltage (11kV), and low voltage (400V) assets, and the on-site assets at each connection such as transformers and associated switchgear.

Most residential (E1) connections in the Western region make use of all the network assets but have limited on-site assets. Industrial connections (W50 price category) often have more on-site assets and make limited use of the low voltage (400V) network assets. The use of these customer groups means prices can better reflect the costs to supply these groups.

4. HOW PRICES ARE SET FOR EACH CUSTOMER GROUP

Prices for customers in both the Eastern and Western regions are set three high-level ways:

- **Standard pricing** for residential and most commercial customers supplied according to the price categories in the standard price schedule
- **Non-standard, customer specific, asset-based pricing** for large connections (>300kVA Western region and >299kVA Eastern region), although also some smaller customers where asset-based pricing is appropriate
- **Non-standard, asset-based, building block pricing** for very large (typically >4MVA) connections, typically requiring a capacity upgrade or large new connection. These customers have a direct contractual relationship with Powerco for a defined term.

We also set prices for distributed generators, including payments to distributed generators providing network support services.

When setting prices, we consider the opportunities to share the value of deferring planned network investment. One way we do this is through a discount for controlled load.

STANDARD PRICING

We set standard prices using the process detailed in the following table.

Table 3: Standard pricing process

Activity	What's involved
Determine customer groups	• Assign customers (connections) to groups for allocating total costs. More detail on how we do this is in Section 3.
Calculate and allocate costs to customer groups	• Confirm the total forecast allowed revenue we can recover for the year. Forecast revenue is determined by the Commerce Commission to reflect efficient costs of supplying distribution services • Calculate expected costs for the year. The main component costs are operating costs (including administration costs), capital costs (including return on investment) and transmission costs • Allocate costs to each customer group to, as closely as possible, align benefit of access and use of the distribution service with the costs of supplying the distribution service • Determine price structures for each customer group based on the required price signals, relevant cost allocations, and complying with the relevant legal requirements More detail on how we do this is in Section 6.
Assess customer impacts of pricing variations	• Check the impact on customers of pricing variations, and adjust pricing as needed More detail on how we do this is in Section 8.

NON-STANDARD PRICING

Non-standard[8] pricing and individual account management is offered to industrial and large commercial customers to provide a tailored service. We offer this when the customer's needs are unique to their business need, eg timing and scale of investment. Our approach to non-standard pricing considers customers' individual capacity and demand to ensure, to the extent practicable, that the price is cost reflective.

We have two non-standard pricing approaches:

- Dedicated onsite assets, with demand-based allocation of *broader* upstream assets
  Price Categories: T50, V40, W50
- Dedicated onsite assets, with demand-based allocation of *specific* upstream assets
  Price Categories: T60, V60, SPECIAL

The number, size and pricing characteristics of non-standard customers are available in Appendix A. We disclose the number of new non-standard contracts each year on our website here.

Customer-specific asset-based pricing

Customer-specific asset-based pricing applies to large connections in both the Eastern and Western regions and others that opt for an asset-based price. Asset-based pricing may also apply to generation connections and special arrangements designed to mitigate the risk of uneconomic asset bypass. Each price is set individually using this process.

[8] A contract is considered non-standard if the price at which the electricity line services are to be provided is not determined solely by reference to a schedule of prescribed terms and conditions that is publicly disclosed

Table 4: Asset-based pricing process

Activity	What's involved
Measurement and forecasts of customer demand and connections	A customer's demand, measured by historical AMD (Anytime Maximum Demand), PCD (Peak Coincident Demand) and ADL (Average Demand Level), is used to calculate asset-based prices
Calculate value of assets supplying the connection, including allocating value of shared assets	The assets used to supply the service are valued in association with RAB values to calculate the asset-based price. Assets are categorised as dedicated on-site assets or shared upstream assets. On-site assets are generally dedicated assets, and wholly allocated to the relevant customer. Upstream assets are allocated using the site's maximum demand and the demand of the section of the network (eg zone substation) that the relevant upstream assets are a part of.
Calculate return of and on capital, and depreciation	An annual rate of return is recovered on the asset valuations attributed to each customer – this is based on Powerco's prevailing weighted average cost of capital (WACC). Depreciation is allocated based on the asset's actual depreciation during the most recent financial year.
Allocate maintenance costs	Maintenance costs are allocated to the relevant load groups based on the load group's RAB relative to the applicable GXP's total RAB. These costs are allocated against the assets used by each customer, using an appropriate rate.
Allocate indirect costs (fixed and variable).	Indirect costs are allocated to load groups based on its total usage as a proportion of the applicable GXP's total usage. Indirect costs are all costs of Powerco's electricity business excluding transmission, asset-related costs, maintenance, interest, and tax.
Allocate transmission costs	Transpower's Connection, Benefit-based, and Residual Charges are allocated to Powerco via various methods. We allocate and pass-through these charges to customers using mechanisms that reflect the TPM and the EA's Pricing Principles and TPM pass-through guidance. The Connection charge is based on the customer's demand, as measured by AMD (load). The Benefit-based and Residual charges are allocated based on historical usage, measured by ADL.

More information on criteria applying when a customer enters an asset-based load group is available in our Pricing Policy, available at: https://www.powerco.co.nz/who-we-are/pricing-and-disclosures/electricity-pricing

Asset-based building block method (BBM)

The asset-based building block method is to set prices for very large (typically >4MVA) customers in both regions. These customers have a direct contractual relationship with Powerco for a defined term, typically for:

- a step change upgrade is needed but the increase in the customer's demand may not be as significant; or
- a new customer connection is required that involves significant investment.

BBM asset-based pricing comprises the following input components:

- return on capital investment, plus accounting depreciation in period or year;
- sub-transmission cost allocation of direct and indirect costs for sub-transmission asset utilisation in period or year;
- operating and maintenance costs;
- tax adjustment; and
- recovery of pass-through costs and recoverable costs (eg transmission charges and regulator levies).

CUSTOMERS ON NON-STANDARD CONTRACTS

Non-standard contracted customers are generally significant commercial or industrial loads, and thus arrangements between the parties include provision for response to planned and unplanned interruptions. For example, customers are given direct contact with Powerco's Network Operations Centre which enables them to liaise directly should a network event occur and help co-ordinate restoration. Some non-standard agreements include operational protocols detailing the management of load in the event of maximum demand levels being reached, or load managed in the event of abnormal network configurations.

These arrangements have no direct effect on the determination of prices for these customers.

PRICING FOR DISTRIBUTED GENERATION

Prices for distributed generation, and any payments from Powerco to distributed generators for network support services, are set according to the Distributed Generation Policy, available here, and in line with Part 6 of The Code.

We do not currently charge distributed generation for exporting electricity via our network on a volume basis.

5. CURRENT PRICING APPROACH AND PLANS TO EVOLVE OUR PRICING

Prices are set taking account of the network, customer, and regulatory characteristics relevant to each of our networks, and how that pricing can promote efficient network use. As such, we recognise the importance of pricing to reflect evolving customer expectations, technology choices, and use of the network.

NETWORK METRICS AND PEAK PRICING

The following table highlights the diversity of the characteristics and costs within pricing zones, by displaying a range of metrics about the cost and use of the network for different locations. The metrics are based on a range of data sources, with the purpose being to allow assessment of relativities of metrics across regions (ie there is no 'right' metric for a region).

- Direct OPEX. This is based on internal records of operational expenditure (eg vegetation management) matched to the GXP and applied across all connections
- RAB/km and RAB/ICP. This reflects the current value of network assets in the area to line length or ICP count. The metric combines asset age (older assets have lower value) as well as the network configuration required to meet customer needs.
- ICPs/km. This reflects network density (higher = more dense, lower = less dense)
- MWh/ICP. Reflects average annual consumption by small customers[9].

Although certain GXPs may have high-cost metrics in one category, they are often balanced by being lower in another category. This provides the ability to group them into appropriate pricing zones, based on their overall cost versus usage and density.

Table 5: Network metrics by GXP

Region	Pricing Zone	GXP(s)	Direct OPEX ($/ICP)	RAB/km ($/km)	ICPs/km	RAB/ICP ($/ICP)	Small Customer Consumption (MWh/ICP)
Valley	VALLEY	Hinuera (HIN0331) & Arapuni (ARI1101)	$232	$53,671	7.4	$7,282	10.5
		Kinleith (KIN0331 & KIN0112)	$480	$68,783	9.7	$7,080	9.1
		Kopu (KPU0661)	$90	$89,904	9.9	$9,051	6.2
		Piako (PAO1101)	$187	$58,613	7.0	$8,363	10.9
		Waihou (WHU0331)	$267	$57,589	5.8	$9,913	11.1
		Waikino (WKO0331)	$97	$61,764	12.5	$4,935	6.1

[9] Large customers are excluded here as they can distort the metric due to the scale of their consumption and because their pricing approach is able to be more closely targeted at their network use.

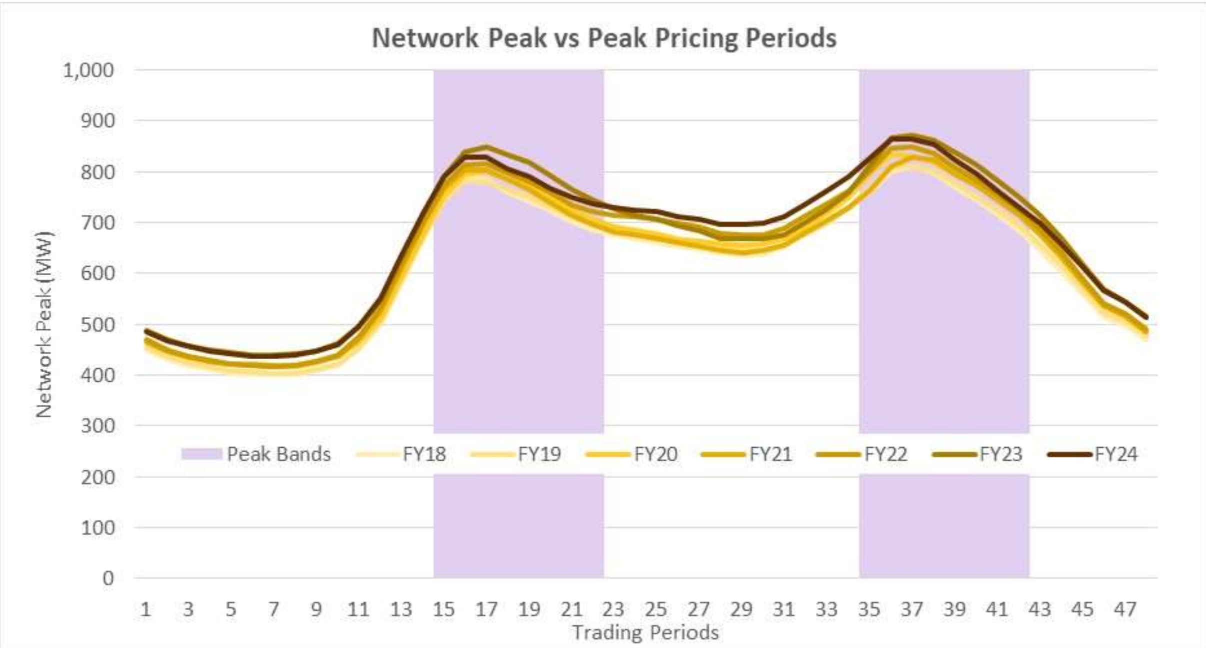
Region	Pricing Zone	GXP(s)	Direct OPEX ($/ICP)	RAB/km ($/km)	ICPs/km	RAB/ICP ($/ICP)	Small Customer Consumption (MWh/ICP)
Tauranga	TAURANGA	Tauranga (TGA0111 & TGA0331)	$177	$99,530	15.9	$6,244	8.3
		Mt Maunganui (MTM0331)	$85	$87,338	19.6	$4,454	7.4
		Te Matai (TMI0331)	$196	$73,411	9.6	$7,638	7.5
		Kaitemako (KMO0331)	$101	$60,661	14.0	$4,338	5.9
Manawatu	A	Bunnythorpe (BPE0331)	$201	$60,686	10.1	$6,028	9.6
		Linton (LTN0331)	$221	$50,069	11.6	$4,314	9.1
	B	Mangamaire (MGM0331)	$189	$44,604	3.4	$13,079	9.4
Taranaki	A	Carrington (CST0331)	$90	$93,949	14.7	$6,386	8.0
		Huirangi (HUI0331)	$203	$48,934	8.3	$5,904	9.5
		Stratford (SFD0331)	$247	$46,593	5.3	$8,869	10.8
	B	Hawera (HWA0331)	$215	$52,312	6.9	$7,617	10.0
		Opunake (OPK0331)	$284	$55,515	4.3	$12,922	14.0
Wanganui	A	Brunswick (BRK0331)	$145	$65,958	11.3	$5,844	7.8
		Wanganui (WGN0331)	$118	$69,499	12.3	$5,672	8.0
	B	Marton (MTN0331)	$180	$42,276	6.1	$6,886	9.8
		Mataroa (MTR0331)	$211	$41,663	3.3	$12,730	8.3
		Ohakune (OKN0111)	$243	$40,664	3.6	$11,323	8.3
		Waverley (WVY0111)	$472	$34,245	3.4	$9,944	12.3
Wairarapa	B	Greytown (GYT0331)	$16	$45,464	6.1	$7,487	10.1
		Masterton (MST0331)	$84	$53,858	8.3	$6,470	8.9

The table below summarises the usage characteristics, network characteristics, and resulting revenue allocation for each pricing zone. This demonstrates the alignment between allocated and forecast revenue at a regional level (rightmost two columns).

Table 6: Network summary

Pricing Zone	ICPs	MWh	Peak Coincident Demand	Coincident Maximum Demand	Regulatory Asset Base (RAB)	COSM Allocated Revenue	Forecast Recovered Revenue
Valley	22%	27%	24%	27%	25%	26%	25%
Tauranga	26%	24%	27%	26%	23%	22%	24%
Eastern	**48%**	**51%**	**51%**	**53%**	**48%**	**48%**	**49%**
A	36%	34%	35%	33%	32%	34%	33%
B	16%	15%	14%	14%	20%	18%	18%
Western	**52%**	**49%**	**49%**	**47%**	**52%**	**52%**	**51%**
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Figure 4: Alignment of network demand to Peak/Off-Peak Periods



Note: The network demands relate to the observation window for the relevant financial year, eg FY24 peaks are observed between September 2021 to August 2022

Figure 4 shows the top 10 network peaks at each half-hourly trading period, overlaid with the time bands that represent Powerco's time-of-use peak pricing. It illustrates that:

- The peak periods used for pricing align with the times that peak network demands occur
- The peak profile is relatively consistent between years, despite the economic and circumstantial (especially weather-based) factors that can affect any one year

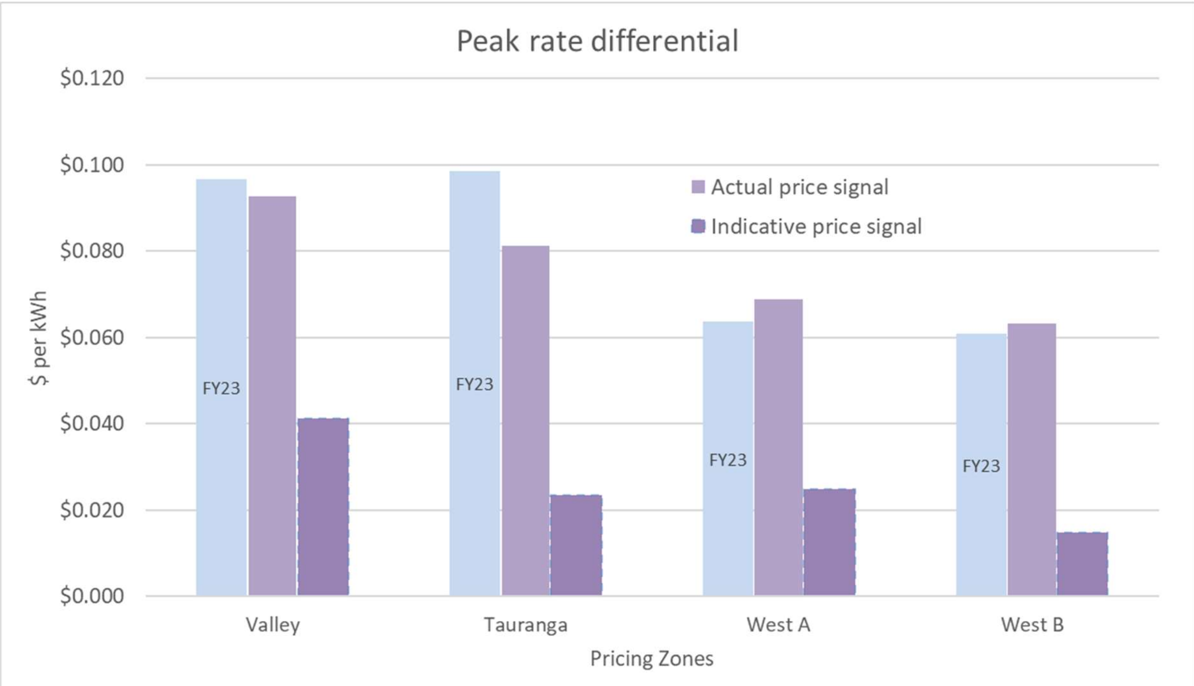
- The peak/off-peak pricing approach, introduced in FY20, does not appear to have had a significant effect on usage patterns. This could reflect a range of factors, such as pass through of prices in retail bills, or relativities of electricity costs to other costs.

The merit of adjusting the time periods is always considered in the context of other factors, such as simplicity (for consumers to understand, and the industry to apply), suitability of the time bands at each network asset level, and consistency with an industry approach – if and when appropriate and efficient to do so.

Having demonstrated that the time-bands used for TOU pricing coincide with peak demands, we then look at the level of prices being signalled at peak periods. Figure 5, below, shows the prior year peak differentials, along with the differentials set for this year, being the combination of transmission and distribution prices. Adjacent to each 'actual' bar is an *indicative* level of the regions' distribution signal[10], based on future investment required.

Comparing the levels of the 'actual' and 'indicative' bars shows that the overall peak pricing differential exceeds the required distribution pricing signal, which is the key metric.

Figure 5: Alignment of pricing signals and investment costs



Note that during FY23 a significant portion of the peak differential was due to the pass through of Transpower's RCPD, which no longer applies. While reducing the differential was considered, there are several reasons to keep this signal strong and stable:

- It's unclear whether the observed demand (in)elasticity is due to lack of pass through by retailers, versus consumers choosing not to alter usage patterns
- The ongoing decarbonisation initiatives, including uptake of EVs, will result in these signals becoming more important over time

[10] There are different ways this value can be assessed. The value shown reflects the annualised value of deferring growth projects by one year, translated into a price that applies at peak times.

- Excessive volatility in the signals is likely to adversely affect customer engagement, which can take years to build

EASTERN REGION – TAURANGA AND THAMES VALLEY

For the Eastern region our prices are set and applied at a customer's metering point. The resulting line charge is passed to the retailer. This is referred to as an Installation Control Point (ICP) approach to set prices.

The splitting of the Eastern region into the Tauranga and Thames Valley pricing zones is mainly due to the differences in demand profiles, customer types and number of customers, population density and network characteristics driving the different needs for investing in these respective parts of the network.

An overview of the current price structure and price components for each customer group is provided in the tables below. More detail on each customer group is provided in Section 3.

Residential and Small Commercial Price Structures (0 – 41kVA)

Prices for most residential and small commercial customers in the Eastern region have a fixed daily price plus several volume-based prices, which can vary depending on the type of meter and controlled load arrangement.

Table 7: Eastern region residential pricing structures

				Variable price options					
Customer group	**Meter type**	**Price categories**	**Fixed price**	**Uncontrolled**	**Controlled**	**Night**	**All inclusive**	**Peak**	**Off-Peak**
				24UC	CTRL	NITE	AICO	PEAK/ PKIN	OFPK/ OPIN
			$/day	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Residential and small commercial	Non-TOU	V05S/T05S V06S/T06S V08	✓	✓	✓	✓	✓		
			✓	✓	✓	✓	✓		
	TOU	V05S/T05S V06S/T06S V08	✓		✓	✓		✓	✓
			✓		✓	✓		✓	✓

Fixed price and variable off-peak prices

The fixed price recovers a portion of Powerco's distribution costs, and excludes any transmission charges, while the variable off-peak prices include a small portion of transmission charges. The fixed price does not fully recover fixed distribution costs for T05S/V05S due to the restrictions of the Low Fixed Charge Regulations.

The variable TOU peak price

The variable TOU peak price recovers part of the distribution cost and most of Transpower's peak-based interconnection charge. Although the difference between Peak and Off-peak prices largely reflects transmission interconnection charges, those are based on demand at peak times, which coincide with peaks on the distribution network. Therefore, we consider this price differential does partly reflect the required distribution price signal.

Uncontrolled, Controlled, and Night-rate prices

We offer a price differential between controlled and uncontrolled load. We use load control to manage network security. This can also support efficient grid utilisation and reduce the need for network investment. Customers who accept controlled load benefit from lower distribution prices. The options differ based on type and duration of control: Controlled (17 hrs/day), Uncontrolled (24 hrs/day), and Night Only (23:00 – 07:00). We have aligned the Controlled and Off-Peak rates as of 1 April 2022, to reflect the benefit to Powerco of being able to shift load from critical peak periods for our network to maintain system security (whether it be for distribution or wider transmission purposes such as the event on August 9, 2021). The NITE tariff is also a form of controlled load and is a separately metered supply to permanently wired appliances.

Temporary Accommodation (V08)

The Coromandel area is supplied by Kopu GXP and experiences significant peaks during holiday periods, often caused by population fluctuations. This can be traced to an ICP level and indicates holiday homes are a significant contributor. Due to the extensive investment in our network required to supply and maintain this area, we are evolving a new category to appropriately reflect the costs. This category (V08) is targeting Connections that meet the definition of Temporary Accommodation[11]. A higher fixed charge than the standard V06S category enables more appropriate cost recovery from these customers, who would otherwise be paying less through variable charges than a standard user, while still significantly contributing to the peaks (which drive the cost of supplying customers off of Kopu). A comparably lower Off-Peak price provides these customers the ability to shape their demand to benefit the network and save on their variable charges also.

Commercial and Industrial Price Structures (42 – 1499 kVA)

Commercial and industrial pricing has components which adjust to reflect the connected capacity of each customer group. The fixed component is cost-reflective, as it’s based on the level of demand that customers place on different elements of our network such as sub-transmission, high voltage (11kV) and low voltage (400V).

Table 8: Eastern region commercial and industrial pricing structures

Customer group	Meter type	Price categories	Fixed price			Reactive Power	Variable charge		
				DIST	TRAN	PFC	24UC	CTRL	TOU
			$/day	$/day	$/day	$/kVAr/mth	$/kWh	$/kWh	$/kWh
Medium commercial	Non-TOU	T22 / V22 T28N / V28N	✓				✓	✓	✓
			✓				✓	✓	
	TOU	T28 / V28	✓			✓	✓	✓	
Large commercial	TOU	V40 / T50		✓	✓	✓			

[11] For details on the eligibility criteria for the Temporary Accommodation (V08) prices please see the full pricing policy here.

Medium commercial and industrial customers

Prices for medium commercial and industrial customers have a two-part structure comprising of a daily fixed price component and a consumption-based kWh variable price. The daily fixed price recovers fixed distribution costs. The variable capacity component recovers variable distribution and transmission costs. Customers with a substandard power factor are subject to a reactive power charge.

Large commercial and industrial customers

Prices vary according to the location, connection capacity, and the peak demands of the individual connection. These custom prices support efficient capacity utilisation because they reflect the capacity used. If a customer's capacity requirements change, they can request to upgrade or downgrade capacity. Customers with a substandard power factor are subject to a reactive power charge.

PRICING IN THE WESTERN REGION – TARANAKI, WHANGANUI, RANGITIKEI, MANAWATU, TARARUA, AND WAIRARAPA

For customers on the Western region, the network service is priced at the point electricity enters the distribution network from the national grid rather than at the customer's connection to the distribution network. Retailers decide how to on-charge their share of the cost of the distribution service to their customers. This is known as a Grid Exit Point (GXP) approach to pricing.

Like the Eastern region, pricing in the Western region is influenced by local network and customer characteristics. The network has significant variations in network density reflecting the relative number of customers to the length of wires. This network density has an impact on the cost of supply, which we reflect using two different (density) zones. Within these zones, customers are grouped according to capacity. Prices in the Western region are set for three customer groups:

- Residential and small commercial - capacity less than or equal to 100kVA
- Medium commercial - capacity between 101-300kVA
- Large commercial and industrial - capacity greater than 300kVA

An overview of the current price structure and price components for each customer group is provided in the tables below. More detail on each customer group is provided in Section 3.

Residential and Small Commercial Pricing Structures (≤100kVA)

The residential and small commercial group is priced using a two-part price structure comprising a fixed daily price and a variable time-of-use price with peak and off-peak components.

Table 9: Western region residential and small commercial pricing structures

Customer group	Meter type	Price categories	Fixed price	Variable price options		
				Peak	Off-Peak	
			FDC	ERP	ERD	ERN
			$/day	$/kWh	$/kWh	$/kWh
Uncontrolled	TOU Non-TOU	E1UCA/E1UCB	✓	✓	✓	✓
Controlled	TOU Non-TOU	E1CA/E1CB	✓	✓	✓	✓

Fixed price and variable off-peak prices

The fixed price recovers a portion of Powerco's distribution costs, and excludes any transmission charges, while the variable off-peak prices include a small portion of transmission charges. The fixed price does not fully recover fixed distribution costs due to the Low Fixed Charge Regulations, so the variable price is higher to compensate. The fixed daily charge for ICPs with Controlled load is lower.

Peak pricing

The variable TOU peak price recovers part of the distribution cost and most of Transpower's peak-based interconnection charge. The difference between Peak and Off-peak prices reflects transmission interconnection charges, and close to the desired distribution pricing signal amount. The transmission interconnection charges are based on demand at peak times, which coincide with peaks on the distribution network.

Commercial and Industrial Price Structures (>100kVA)

Commercial and industrial pricing has components which adjust to reflect the connected capacity of each customer group. The fixed component is cost-reflective, as it's based on the level of demand that customers place on different elements of our network such as sub-transmission, high voltage (11kV) and low voltage (400V).

Table 10: Western region commercial and industrial pricing structures

Customer group	Meter type	Price category	Fixed price			Demand based	Variable price
			Per ICP	DIST	TRAN	PFC	
			$/day	$/day	$/day	$/kVAr	$/kWh
Medium commercial	TOU	E100	✓	✓	✓	✓	✓
Large commercial	TOU	W50		✓	✓	✓	

Medium commercial and industrial customers

Prices for medium commercial and industrial customers have a structure comprising of a daily fixed price component, prices based on historical demand and a small consumption-based kWh variable price. Customers with a substandard power factor are subject to a reactive power charge.

Large commercial and industrial customers

Prices vary according to the location, connection capacity, and the peak demands of the individual connection. These custom prices support efficient capacity utilisation because they reflect the capacity used. Customers with a substandard power factor are subject to a reactive power charge.

SHARING VALUE OF DEFERRAL OF INVESTMENT

We see the potential for customers to help us defer network upgrades and improve quality of supply by providing network support services. This could be from demand response or distributed generation and could be directly (eg hot water load control) or indirectly (eg a third-party provider).

We share the value of deferring investment with customers providing network support services in several ways.

Load control

Our prices across both regions reflect the difference in long-term costs associated with investment in additional capacity in the distribution network.

- Residential customers in the Western region (the E1 customer group) offering control of their hot water have the daily fixed price discounted from 30 cents/day to 15 cents/day.
- Residential customers in the Eastern region (the T/V05S and T/V06S customer groups) offering control of their hot water receive discounts to the volume-based prices based on the availability and duration of load control.
- NITE price option is also a form of controlled load and is a separately metered supply to permanently wired appliances. No uncontrolled appliances are connected to NITE supply meter. The Load Control Equipment when in operation must result in the reduction to zero of all controllable loads and all load connected to the NITE supply meter.

Configured well, load control systems are highly effective at reducing demands at peak times by deferring non-time-critical power usage. The benefits of load-control systems include more predictable peak demand magnitudes, fewer peaking generation plants and deferred transmission and distribution capacity augmentations. The benefits accrue across the entire electricity sector.

Demand-based allocation

Powerco’s demand-based prices in the Western region are applicable to larger commercial and industrial customers. They are designed to reflect the relative costs of distribution and

transmission for those customers groups and are further split by GXP groupings. This pricing method is an alternative to full asset-based pricing for each connection, while being more cost-reflective than using kWh-based prices.
Note: The demands are observed historically and applied as fixed charges in the following year.

Standalone power systems

We also support deferral and avoidance of investment through installation of standalone power systems where the efficient option is to provide an alternative energy supply rather than replacing network assets. In some cases, the cost of renewing these assets is greater than the present value of the line charges that would be recovered over the lives of the assets.

EVOLVING OUR PRICING AND PRICES

We are evolving our pricing and prices. You can find the detail on how we are doing this in our pricing roadmap, available here.

Our pricing approach had incremental changes over the last few years to improve the alignment of cost with prices, and the predictability of line charges for retailers. This provided retailers and customers with a degree of certainty when making decisions about retail pricing, and investment in energy saving and off-peak devices.

However, changing customer preferences, technology, and retail markets are influencing how our network is used, so our pricing approach may need to evolve too. We need to balance the need for our prices to reflect the costs of supplying each customer with other considerations, like being workable and predictable for retailers. We also need to make sure our pricing complements changes to the external environment, such as the roll out of advanced metering infrastructure, the fall in cost of photovoltaic technology, and the way transmission prices are derived.

As a first step, we plan to replace the GXP approach to pricing in the Western region with an ICP methodology (as used in the Eastern region) in the coming years. ICP pricing more closely reflects retailer prices and consequently makes it possible to provide a greater number of targeted price signals to specific regions, customer groups, or individual customers to promote efficient use of the network. The transition involves significant system changes and requires access to consumption data so we can set prices accurately. It will require us to work with retailers to ensure a manageable transition between methodologies, including assessment of customer impacts.

Longer-term pricing direction

Powerco is subject to a regulated revenue allowance. A benefit of this approach is that it removes potential barriers to more cost-reflective pricing structures, such as by eliminating the risks involved with forecasting volumes. Powerco's roadmap reflects the removal of these barriers, including initiatives that will improve the alignment between costs and prices.

Issues we will continue to monitor over the next five years are:

- Improving the alignment of fixed price components with fixed costs

- The impact of stronger peak demand pricing signals, both in terms of how narrowly peaks are targeted, and the actual pricing levels, on different types of customers' electricity usage
- The benefits and consequences of greater alignment of the pricing approaches used in the Eastern and Western regions
- The needs of customers when we are making price adjustments
- Customer preferences towards the way costs are allocated and reflected in prices
- Development and uptake of new technologies, such as PV and EVs, and the impacts these will have on our network
- Applying pricing signals meaningfully and only when required (ie using prices to signal to avoid congestion when there is a genuine cost to avoid)

6. CHANGES TO OUR PRICING APPROACH AND PRICES IN FY24

The Pricing Schedule for 2023-24 sets out the specific prices for customers connected to our networks. It is available on our website here. The prices reflect a total average increase in forecast revenue of 8.80% compared to last year.

The change in forecast revenue for the Eastern and Western regions is shown in the table below.

Table 11: Changes to Powerco's total forecast revenue

	Forecast Revenue ($000):			
	FY23	**FY24**	**$ Change**	**% Change**
Eastern region	193,870	208,158	14,288	7.4%
Western region	198,855	219,120	20,265	10.2%
Total	**392,725**	**427,278**	**34,553**	**8.8%**

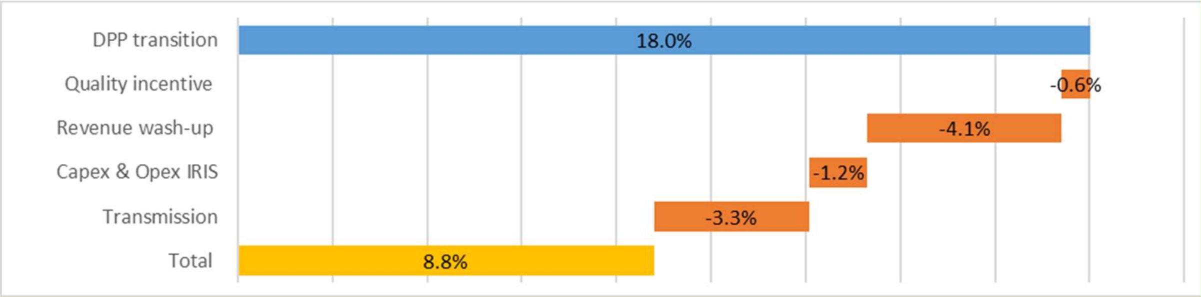
The reasons for changes to forecast revenue are described in the following table.

Table 12: Reasons for changes to forecast revenue

Change	Description
DPP Transition	Powerco's forecast net allowable revenue, which excludes pass-through and recoverable costs, and any wash-up draw down, has increased by $70.8m, to $321.7m. This is due to moving from a Customised Price Path to the Default Price Path, and adjustments to allowances for inflation, and vegetation management.
Quality incentive adjustment	The quality incentive scheme allows Powerco additional revenue for performing better than the quality targets, and less revenue for performing below the quality targets. The overall quality incentive adjustment for FY24 is -$1.3m, compared to +$0.6m in FY23.
Revenue wash-up	An annual 'wash-up' of the difference between the revenue received and allowable revenue is calculated. The revenue wash-up amount for FY24 is +$14.5m, compared to +$25.8m in FY23. This washup largely relates to the early replacement of aged assets due to growth or reliability requirements, and is effectively the accelerated depreciation on those assets. It is referred to 'loss on disposal' in regulatory accounting terms.
Capex and Opex IRIS	The IRIS mechanisms are designed to incentivise efficient capital and operating expenditure. The net adjustment to revenue is -$5.7m for FY24, compared to +$0.1m for FY23. This means Powerco's actual expenditure in preceding years was lower than our allowance, and we are returning a portion of that through our total pass through and recoverable costs.
Change in transmission costs	Transpower has adopted a new Transmission Pricing Methodology for FY24, which has materially altered the cost allocation across its customers. Powerco's FY24 transmission charges, including pass through costs, have dropped to $98.1m in FY24, from $111.0m in FY23.

The figure below presents these to illustrate the impacts for each change relative to the overall change in allowable revenue.

Figure 6: Percentage contribution to change in allowable revenue (FY23 vs FY24)



Prices have been adjusted, after consultation with retailers, to reflect this change. There have been some other changes to our pricing approach, as described and summarised below.

Table 13: Changes to pricing from 1 April 2023

Change	Description
Change in variable charge elements	The night rate is aligned with the off-peak rate, reflecting that night usage is purely in off-peak hours. The all-inclusive rates are aligned to our uncontrolled rates, to reflect the fact these meter types do not provide sufficient information to warrant a discounted rate
Change in fixed charge elements	The electricity low fixed-charge tariff option is being phased out by the Government over five years, starting from 1 April 2022. In line with this, the daily fixed charge for low user tariffs will rise from 30 cents per day to 45 cents per day from 1 April 2023.

7. CALCULATING AND ALLOCATING COSTS ACROSS CUSTOMER GROUPS

For the FY24 pricing year, Powerco's total forecast revenue is $427.3m. We set prices to recover this amount by calculating and allocating costs across each customer group. The process involves:

- Calculating the total forecast revenue allowed by the Commerce Commission for the pricing year
- Identifying our major cost components, and whether the costs are fixed or avoidable
- Determining price signals required to reflect the expected costs of future investment
- Allocating costs to specific customer groups
- Checking alignment between cost types and price components

PRICES ARE SET TO REFLECT MAJOR COST COMPONENTS

We use categories of operating and maintenance costs, depreciation, cost of capital, and transmission and other pass-through costs, such as local authority rates. The following table details the forecast costs for each of these categories for the FY24 pricing year.

Table 14: Expected costs of supplying distribution services in the FY24 pricing year

Cost	Eastern region ($000)	Western region ($000)	Total ($000)
Operating and maintenance costs	$49,901	$55,564	**$105,465**
Depreciation	$52,603	$62,676	**$115,279**
Cost of capital	$54,658	$53,784	**$108,442**
Transmission costs[12]	$50,996	$47,096	**$98,092**
Forecast Revenue	**$208,158**	**$219,120**	**$427,278**

More detail on each of these costs is provided below. Detailed information on Powerco's forecast and historical costs are available in Powerco's disclosures to the Commerce Commission. These disclosures include Powerco's Asset Management Plan, which contains forecasts of demand and costs for the next 10 years.[13]

Operating costs

Operating costs are the day-to-day costs of providing the distribution service, including:

[12] This includes other pass-through and recoverable costs (which comprise around 5%)
[13] Our disclosures, including Asset Management Plans are available here

- Network operation costs
- Network planning and asset management costs
- Network management and dispatch costs
- The cost of support services such as billing, record management, planning, contract administration, regulatory compliance, and resource costs
- Statutory charges and levies (excluding those that are pass through costs)

Depreciation

This component includes recovery of the depreciation on the network assets, which is part of our revenue allowance.

Cost of Capital

The cost of capital component includes recovery of the cost of debt and equity invested in Powerco, and the tax expense. Powerco requires large amounts of capital to maintain and develop network assets. Historical capital expenditure by type (eg system growth, replacement and renewal) is available on Powerco's website. Powerco's asset management plan provides a large amount of detail on the drivers of capital expenditure for the network.

Transmission costs

The transmission component includes all recoverable costs, such as Transpower's Connection, Benefit-based, Residual, and New Investment charges, as well as pass through costs such as council rates and statutory levies.

Transpower's charges are set according to the transmission pricing methodology determined by the Electricity Authority and 'passed through' to customers in our prices. More detailed information on the pass-through of transmission charges is available in Table 17.

ALIGNING COSTS AND PRICES ACROSS CUSTOMER GROUPS

Firstly, costs are allocated to customer groups and pricing zones. The allocation is a function of the load characteristics of the customer groups, network use, and cost of supply. When costs are directly attributable to a group or zone, they are allocated directly to them. When they aren't, we allocate more broadly. In summary:

- Operating costs: allocated to GXPs where attributable, spread broadly otherwise.
- Transmission costs: allocated to GXPs. Within each GXP, allocated based on demand.
- Cost of capital: allocated based on the value of assets in each network region

Pricing structures for each customer group are intended to marry the cost components with the attribute that drives it. Our intention is to recover fixed costs using fixed price components and avoidable costs using avoidable cost components. For example, we want the fixed daily price for residential customers to recover fixed costs. However, it is not practicable to do so yet for several reasons, such as the LFC regulations and data quality.

Eastern region

Powerco's price structure in the Eastern region has been designed so that customers with higher connected capacity have a higher fixed component than those with lower connected capacity. This benefits both Powerco and customers by making line charges more predictable and more closely related to the actual cost of supply.

This approach also helps to ensure that customers have the right incentives to state their capacity requirements. Larger capacity price categories have the bulk of their line charges fixed, while lower capacity categories have a lower fixed component (as shown in the table below).

Powerco's ability to align the price structure with costs is restricted by Low Fixed Charge Regulations which distort the balance between and levels of fixed and variable prices. Powerco determines the proportion of fixed and variable charges by reference to existing rates while recognising the largely fixed nature of the underlying costs. The regulations have a large influence on the level of the fixed and variable components for residential groups.

Table 15: Eastern region target revenue requirement split by fixed and variable price components for each customer group (FY24 pricing year)

<table>
<tr><th rowspan="2">Zone</th><th rowspan="2">Customer Group</th><th rowspan="2">Price Category</th><th rowspan="2">ICPs</th><th colspan="4">Target Revenue Split</th></tr>
<tr><th>Fixed</th><th>Variable</th><th>Other[14]</th><th>Total</th></tr>
<tr><td rowspan="7">Tauranga</td><td rowspan="3">0-41kVA</td><td>Unmetered (T01/T02)</td><td>293</td><td>84.3%</td><td>15.7%</td><td>-</td><td>100%</td></tr>
<tr><td>Low Usage (T05)</td><td>35,374</td><td>28.1%</td><td>71.9%</td><td>-</td><td>100%</td></tr>
<tr><td>Standard (T06)</td><td>55,917</td><td>43.6%</td><td>56.4%</td><td>-</td><td>100%</td></tr>
<tr><td rowspan="2">42-299kVA</td><td>3 Phase 60 – 3 Phase 250 Amps (T22)</td><td>730</td><td>45.5%</td><td>54.5%</td><td>-</td><td>100%</td></tr>
<tr><td>200 - 299 kVA (T28)</td><td>153</td><td>40.8%</td><td>57.4%</td><td>1.8%</td><td>100%</td></tr>
<tr><td rowspan="2">300 kVA + (incl. non-standard customers)</td><td>300 – 1,499 kVA (T50)</td><td>233</td><td>97.6%</td><td>-</td><td>2.4%</td><td>100%</td></tr>
<tr><td>1,500 kVA + (T60)</td><td>38</td><td>97.8%</td><td>-</td><td>2.2%</td><td>100%</td></tr>
<tr><td rowspan="8">Valley</td><td rowspan="4">0-41kVA</td><td>Unmetered (V01/V02)</td><td>214</td><td>84.9%</td><td>15.1%</td><td>-</td><td>100%</td></tr>
<tr><td>Low Usage (V05)</td><td>37,320</td><td>26.5%</td><td>73.5%</td><td>-</td><td>100%</td></tr>
<tr><td>Standard (V06)</td><td>37,145</td><td>34.1%</td><td>65.9%</td><td>-</td><td>100%</td></tr>
<tr><td>Temporary Accommodation (V08)</td><td>-</td><td>-</td><td>-</td><td>-</td><td>0%</td></tr>
<tr><td rowspan="2">42-299kVA</td><td>3 Phase 60 – 3 Phase 250 Amps (V22)</td><td>551</td><td>35.2%</td><td>64.8%</td><td>-</td><td>100%</td></tr>
<tr><td>200 – 299 kVA (V28)</td><td>48</td><td>40.8%</td><td>58.6%</td><td>0.6%</td><td>100%</td></tr>
<tr><td rowspan="2">300 kVA + (incl. non-standard customers)</td><td>300 – 1,499 kVA (V40)</td><td>90</td><td>97.7%</td><td>-</td><td>2.3%</td><td>100%</td></tr>
<tr><td>1,500 kVA + (V60)</td><td>30</td><td>98.5%</td><td>-</td><td>1.5%</td><td>100%</td></tr>
</table>

[14] Including reactive power charges (where applicable).

Western region

As for the Eastern region, distribution costs are largely fixed rather than related to the delivered energy volumes. Again, the Low Fixed Charge Regulations affect the balance between fixed and variable prices and are exacerbated when applied to GXP pricing. As a result, charges for residential and small commercial customers (E1 in the below table) are mostly variable, despite most network costs being fixed.

Customers in the E100 and W50 price categories are typically very large commercial or industrial businesses requiring dedicated on-site and upstream assets (such as dedicated feeders and transformers) to meet their supply requirements. The fixed price component of these price categories is typically higher than the other price categories to ensure that an appropriate return on investment is earned by Powerco.

Table 16: Western region target revenue requirement by fixed and variable price components for each customer group (FY24 pricing year)

Customer Group	Price Zone	ICPs	Target Revenue Split			
			Fixed	Variable	Other[15]	Total
E1 (up to 100 kVA)	A	124,467	15.7%	84.3%	-	100%
	B	55,597	11.9%	88.1%	-	100%
E100 (101 – 300 kVA)		287	74.2%	22.6%	3.1%	100%
W50 (301 kVA+)		233	97.7%	-	2.3%	100%
SPECIAL (1500 kVA+)		57	98.6%	-	1.4%	100%

[15] Including reactive power charges (where applicable).

8. ASSESSING CUSTOMER IMPACTS

We assess the impact on customers of each change to price structure and price level. We take account of:

- The scale of changes to line charges for customers or a customer group
- Whether the price structure is workable for retailers to adopt and apply
- The transaction costs associated with applying the price structure.

WE ASSESS THE IMPACT OF PRICE CHANGES

The average line charge, including transmission, for residential customers is about 38%[16] of the total electricity bill. The demographic profile of our networks is diverse. We work hard to understand the impact of changes to our pricing on households, and to design our pricing to avoid large changes to line charges (or 'bill shocks').

A customer's line charges can vary for several reasons:

1. Changes to the Commerce Commission's Price-Quality path decision. For example, changes to the Weighted Average Cost of Capital that affects our allowable revenue. These changes are largely outside of our control.
2. Changes we make to our pricing methodology and revenue allocation between groups. These changes are largely within our control.
3. Changes in the way a customer is using the network – be that capacity, consumption, or other ways.

Identifying material price changes

We use a Cost of Supply Model (COSM) to evaluate how the pricing approach recovers different categories of cost from specific customer groups, and to identify potential customer impacts.

We assess price changes for residential and commercial/industrial customers differently. For residential customers we assess the price impact by examining the average change in price for all customers (to assess the average impact on customers). We engage with retailers about how any changes might impact on their customer bills. For commercial/industrial price categories, because there are significantly less customers, we can assess price impacts at a more granular level. If necessary, we implement changes in phases to mitigate the risk of price shocks.

[16] Based on https://www.ea.govt.nz/consumers/my-electricity-bill/

Checking price outcomes are subsidy-free

Finally, we check prices are within the subsidy-free zone. This involves checking that average prices for each customer group are between the estimated avoidable and stand-alone cost of supplying them.

Our prices reflect the economic costs of service provision, by allocating costs based on the shares of network benefit that consumers receive. Residential/small commercial connections make up 99% of all connections on our network. They use approximately 8MWh per year for an average network cost of approximately $900 per year.

- Avoidable costs for an existing consumer are negligible (near zero) since almost all distribution costs relate to shared assets or services.
- Standalone costs on an ongoing basis, are calculated at between $5,000-$10,000 per year (including energy cost). We calculated the standalone costs based on the alternative supply of a residential consumer, using solar panels and batteries, or a generator with solar panels and batteries.

Price-quality path changes

We mitigate price impacts by calculating the customer impact before finalising our prices. If the COSM analysis is significantly different from the revenues recovered through existing prices, prices are adjusted to ensure a better alignment of revenues and costs. This means that changes to prices (up or down) are linked to the costs that drive them.

CUSTOMER ENGAGEMENT

We actively engage with our customers to understand what they value – we need our network to meet their needs, both now and in the future[17]. For example, our customer engagement has found that customers have an increasing willingness to take control of their energy options. This has influenced our strategy to invest in resources to study customer trends and emerging requirements, so we can prepare our network to accommodate them.

We use a variety of means to engage with our customers and capture their feedback about how we manage our network, including pricing. These include:

- Direct interaction with larger commercial and industrial customers
- Customer initiated engagement through promotion of customer facing communication channels
- Customer surveys
- Annual retailer consultations
- Stakeholder meetings and focus groups
- Website, digital services, and phone feedback

[17] Our customer base includes retailers and their customers, directly contracted industrial businesses, local territorial authorities, and the NZTA.

- Stands at agricultural field days, exhibitions, and trade shows where customers can provide face-to-face interaction

A key step in setting prices is a consultation process with retailers. We welcome their insights about customer preferences towards pricing.

Findings of our customer engagement surveys are reflected in our asset management planning process along with other key drivers such as safety and resilience. Details of our approach and findings of the 2019 consultation programme are published in our most recent Electricity Asset Management Plan (2019).

WE SET WORKABLE PRICES FOR RETAILERS TO ADOPT AND APPLY

Powerco consults with retailers and other customers several times throughout the year to discuss pricing issues (including potential improvements) and the impact of any pending review of our prices. A description of this process is available on request from Powerco. Powerco is aware of transaction costs and seeks to minimise them where feasible. Some examples of transaction costs that exist when Powerco transacts with key groups, and how we take these into account, are:

- **Retailers:** Transaction costs can occur when billing systems, the pricing strategy and/or risk management strategy are amended to accommodate large distribution price changes. Over twenty retailers operate on Powerco's network, and we have a detailed pricing consultation process, usually involving two rounds of consultation. There is a balance between rationalising price categories and options to minimise retailer transaction costs against more individualised pricing which some new retailers can accommodate easily with modern systems.

- **Customers:** Customers make medium to long-term investments based on electricity price structures. For example, a very low price for consumption may provide an incentive to invest in a storage heater. Powerco is aware that customers value pricing certainty and aims to minimise any large changes that impact these types of investment decisions. For residential customers we consider feedback from retailers (as they have responsibility for the ultimate price signal). We also collect information from commercial customers via direct engagement.

9. ALIGNMENT WITH ELECTRICITY AUTHORITY PRICING PRINCIPLES

The table below provides commentary about how our pricing approach aligns with the Electricity Authority's Pricing Principles (available here).

PRINCIPLE	ALIGNMENT DEMONSTRATED
A1 Prices are to signal the economic costs of service provision, including by being subsidy free (equal to or greater than avoidable costs, and less than or equal to standalone costs)	Forecast total revenue recovered from each customer or customer group falls between standalone and avoidable costs. This is discussed in Section 8. Sections 3, 4 and 7 describe how we set prices to reflect the cost of supply for each customer or customer group, and check cost allocations using our cost of supply model.
A2 Prices are to signal the economic costs of service provision, including by reflecting the impacts of network use on economic costs	We set prices to reflect the impacts of network use on economic costs, to the extent practicable. As described in Sections 2, 4 and 7, the prices for each customer group are designed to recover fixed costs and to signal avoidable costs, for each location. This is achieved by the components of the price structure for each customer group aligning to specific types of costs, to the extent practicable (eg the LFC Regulations require us to set prices which discourage consumption).
A3 Prices are to signal the economic costs of service provision, including by reflecting differences in network service provided to (or by) consumers	We set prices to reflect differences in the network service provided to, or by, customers. Section 5 describes how residential customers across both networks can choose controlled rate pricing which provides them a price discount in return for allowing us to reduce part of their consumption at pre-specified times. Our non-standard pricing for commercial and industrial customers allows those customers to obtain and pay for a distribution service which reflects their specific supply requirements. Section 8 describes how our customer engagement activities aid our understanding of customer preferences and informs our asset planning. We also use the insights from the Electricity Network Association's customer engagement surveys and focus groups.

PRINCIPLE	ALIGNMENT DEMONSTRATED
A4 Prices are to signal the economic costs of service provision, including by encouraging efficient network alternatives	We set prices to encourage efficient network alternatives. Section 5 describes how our pricing approach provides an incentive for commercial and industrial customers to manage the power factor and recover costs. The Powerco connection standard specifies that power factor correction is best applied at customers' installations. Section 4 refers to our Distributed Generation Policy, which includes a mechanism for distributed generators to receive payments when they supply us a network support service. Additionally, our network management approach supports procurement of efficient network alternatives by tendering for solutions on a case-by-case basis. The benefits are reflected in lower costs of supply, and lower prices.
B Where prices that signal economic costs would under-recover target revenues, the shortfall should be made up by prices that least distort network use.	We set prices to recover the cost of supplying distribution services, and to signal the opportunity for customers to avoid costs. As described in Sections 4, 5 and 7 the components of our prices are intended to recover the fixed costs and the avoidable costs associated with supplying specific customer groups, to the extent practicable. We are working to align the fixed and avoidable price components with the relevant costs.
C Prices should be responsive to the requirements and circumstances of end users by allowing negotiation to reflect the economic value of services and enable price/quality trade-offs	We offer non-standard contracts and pricing to customers – primarily large commercial and industrial – to reflect their specific circumstances and cost of supplying distribution services, and to reduce the risk of inefficient demand curtailment, disconnection or not connecting. Our approach is described in Section 4.
D Development of prices should be transparent and have regard to transaction costs, consumer impacts, and uptake incentives.	Our approach to pricing and setting prices is described in this Pricing Methodology document and is available to customers and interested people from our website and on request. For example, the "More for less" dedicated webpage was used for the FY21 pricing changes, and included a survey option. We engage regularly with customers, retailers and other interested people on pricing, reliability and quality of supply and investment plans. For example, we are surveying customers to understand more about their perceptions of our pricing during the coming year. Extensive information is available through our website, Asset Management Plan, and other publications. Our goal is to make good information available to people using our network (or wanting to in the future) for them to make the best possible decisions about energy-related investments and electricity use.

10. HOW WE MEET THE COMMERCE COMMISSION INFORMATION DISCLOSURE REQUIREMENTS

The table in this section provides commentary about how this pricing methodology complies with 2.4.1 to 2.4.5 of the Electricity IDD.

Information Disclosure Requirement	Compliance demonstrated
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 below, used to calculate the prices payable or to be payable;	Powerco's Electricity Pricing Methodology achieves this.
(2) Describes any changes in prices and target revenues;	See Section 6.
(3) Explains, in accordance with clause 2.4.5 below, the approach taken with respect to pricing in non-standard contracts and distributed generation (if any);	See Section 4.
(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.	See Section 8.

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.	

2.4.3 Every disclosure under clause 2.4.1 above must-	
(1) Include sufficient information and commentary to enable interested persons to understand how prices were set for each consumer group, including the assumptions and statistics used to determine prices for each consumer group;	See Appendix A.
(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;	See Section 9.
(3) State the target revenue expected to be collected for the disclosure year to which the pricing methodology applies;	See Section 6.
(4) Where applicable, identify the key components of target revenue required to cover the costs and return on investment associated with the EDB's provision of electricity lines services. Disclosure must include the numerical value of each of the components;	See Section 7.
(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;	See Section 3.
(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;	See Section 6.

Information Disclosure Requirement	Compliance demonstrated
(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;	See Section 7, and Appendix A.
(8) State the proportion of target revenue (if applicable) that is collected through each price component as publicly disclosed under clause 2.4.18.	See Appendix A.

2.4.4 Every disclosure under clause 2.4.1 above 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;	Section 5 describes the pricing approach Powerco is adopting.
(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.	

2.4.5 Every disclosure under clause 2.4.1 above 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;	See Section 4 and Appendix A.
(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;	See Section 4.
(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.	See Section 4.

DEFINITIONS

This pricing methodology uses industry standard terms where possible. A glossary of common terms is included for clarity. Additional information on definitions used in the document can be found in:

- Powerco's Electricity Pricing Schedule, Distributed Generation Policy and Asset Management Plan[18]; and
- The Commerce Commission's electricity default price-quality path notice and information disclosure requirements.[19]

Anytime Maximum Demand (AMD) means the highest kW peak occurring any time in the 12-month period from 1 September to 31 August, the result of which is applied in the subsequent Price Year commencing 1 April.

Average Demand Level (ADL) means the Consumer's average level of kW demand across the 12-month period from 1 September 2021 to 31 August 2022, the result of which is applied in the subsequent Price Year commencing 1 April 2023

Avoided Cost of Transmission (ACOT) is the amount equal to the actual reduction in the charges that are payable by Powerco to Transpower under the Grid Network Agreement. ACOT charges are a substitute for what otherwise could have been Transpower charges and are regulated by the Electricity Authority.

Coincident Maximum Demand (CMD) is the highest kW peak of each GXP, measured in accordance with the AMD method, but accounts for interconnection of certain GXPs.

Connection or **Point of Connection** means each point of connection at which a supply of electricity may flow between the Distribution Network and the Customer's installation, as defined by the Distributor.

Customer means a purchaser of electricity from the Retailer where the electricity is delivered via the Distribution Network.

Customised Price Path Determination or **CPP Determination** means the Powerco Limited Electricity Distribution Customised Price-Quality Path Determination 2018. This sets out the price path and quality standards the Powerco must comply with over the period 1/4/2018 to 31/3/2023.

COSM means Powerco's Cost of Supply Model.

Demand means the rate of expending electrical energy expressed in kilowatts (kW) or kilovolt amperes (kVA).

Distributed Generation or **Embedded Generation** means electricity generation that is connected and distributed within the Network.

[18] Available at www.powerco.co.nz.
[19] Available at www.comcom.govt.nz.

Distributed Generator or **Embedded Generator** means an electricity generation plant producing Embedded Generation.

Distribution Network or **Network** means:

Network region	Area	Transpower GXP
Eastern	Valley (Thames Valley)	Arapuni Hinuera Kinleith Kopu Piako Waihou Waikino
	Tauranga	Tauranga Mt Maunganui Te Matai Kaitimako
Western	Wairarapa	Greytown Masterton
	Manawatu	Bunnythorpe Linton Mangamaire
	Taranaki	Carrington Huirangi Hawera Opunake Stratford
	Whanganui	Brunswick Marton Mataroa Ohakune Whanganui Waverley

Distributor means Powerco Limited, as the operator and owner of the Distribution Networks, and includes its subsidiaries, successors, and assignees.

Electricity Authority (EA) means the Electricity Authority which is an independent Crown entity responsible for regulating the New Zealand electricity market.

Grid Exit Point (GXP) means a point of connection between Transpower's transmission system and the Distributor's Network.

High-Voltage (HV) means voltage above 1,000 volts, generally 11,000 volts, for supply to Customers.

Installation Control Point (ICP) means a Point of Connection on the Distributor's Network, which the Distributor nominates as the point at which a Retailer is deemed to supply electricity to a Customer, and has the attributes set out in the Code.

kVA means kilovolt–ampere (amp).

kVAh means kilovolt ampere hour.

kVAr means kilovolt ampere reactive.

kW means kilowatt.

kWh means kilowatt hour.

Line Charges means the total charges levied by the Distributor on Customers for the use of the Distribution Network, as described in the Pricing Schedule. This is the combination of Powerco's prices with the relevant quantities.

Low Fixed Charge Regulations – Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004. These are available here: https://www.legislation.govt.nz/regulation/public/2004/0272/latest/DLM283614.html

Low Voltage (LV) means voltage of value up to 1,000 volts, generally 230 or 400 volts for supply to Customers.

MVA means Megavolt Ampere.

Network see **Distribution Network**.

Peak Coincident Demand (PCD) is the Consumer's average demand during the top 100 peak periods observed on Powerco's network. The peak periods are observed between 1 September 2021 and 31 August 2022 for the Price Year effective 1 April 2023. The PCD is used in calculating the Delivery Charges of a Consumer on Price Categories such as V40, T50, V60, T60 in the Eastern Region and E100, W50, and SPECIAL Price Categories in the Western Region.

Point of Connection means the point at which electricity may flow between the Network and the Customer's Installation and to which an Installation Control Point is allocated.

Powerco means Powerco Limited and any of its subsidiaries, successors, and assignees.

Power Factor is the ratio of active energy, measured in kilowatts (kW), to apparent energy, measured in kilovolt amperes (kVA). Reactive power, measured in kilovolt amperes reactive (kVAr), results from a non-parity power factor and may incur charges.

Price Category means the relevant price category selected by the Distributor from this Pricing Schedule to define the Line Charges applicable to an ICP.

Price Option means the price option within a **Price Category** where such a **Price Category** provides for **Retailer** choice amongst two or more options, subject to a particular configuration of metering and load control equipment.

Price Year means the 12-month period between 1 April and 31 March.

Recoverable Costs has the meaning specified in clause 3.1.3 of the Commerce Act (Electricity Distribution Services Input Methodologies) Determination 2012.

Region means the Eastern region or the Western region.

Registry means the Electricity Authority central Registry**.**

RAB means Powerco's Regulatory Asset Base - the value of assets used to provide the network service and publicly disclosed by Powerco under Information Disclosure requirements.

Retailer means the supplier of electricity to Customers with installations connected to the **Distribution Network**.

Temporary Accommodation means a non-primary place of residence in the context of the Electricity (Low-Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004, such as holiday homes and other non-permanent places of residence that are predominantly not business premises.

Time of Use Meter (TOU) means metering that measures the electricity consumed for a particular period (usually half-hourly) and complies with Part 10 of the Code.

APPENDIX A: ALLOCATION OF COSTS ACROSS CUSTOMER GROUPS AND PRICE ZONES

This appendix summarises the approach and resulting allocations of costs to price zones and customer groups in each network region. The table below summarises our main cost components and the approach to allocating them.

Table 17: Cost allocations to customer groups

Cost component	Allocation approach
Operating costs	Allocated directly to the GXP where the operating costs are incurred. Where we cannot attribute operating costs to a location, the costs are allocated to each network based on the assets, ICPs, and energy usage within the network. Common operating costs relating to the electricity business, eg administration costs, are allocated between regions and customer groups using each group's contribution to system demand, consumption and ICP numbers, depending on the type of expense. These costs are shared by all users, but the methodology recognises the contribution larger customers make to these costs.
Cost of capital and depreciation	Allocated to each network based on the RAB values and depreciation of the assets within each network. The cost of capital and depreciation charges are allocated between customer groups, based on the aggregate of the maximum demands contributed by each group.
Transmission costs	Transpower's Connection charge is directly attributed to GXPs. Allocation is based on customer demand, as measured by AMD (load). This provides a proxy for customers' size and ability to pay, while using a historical measure, across a 12-month period, aligning the stable nature of the cost with a charge that does not provide a strong price signal. Transpower's Benefit-based and Residual charges are allocated to Powerco based on historical usage. These costs are then allocated between customer groups in each location based on their portion of historical usage, as measured by ADL. The historical observation limits the avoidance of the charge, but recognises changing usage by customers over the medium term. While ADL currently uses a 12-month historical observation, this will evolve as the effects of the new TPM become apparent. Effects may include customer behaviours around avoiding charges, the requirement for, and impact of, Benefit-based investments.

For the Eastern region, the table below sets out the allocations of costs to customer groups and zones, with the following table showing the resulting cost values.

Table 18: Cost allocations to Eastern region customer groups

Price Zone	Customer Group	Allocator For:		
		Operating Costs	Cost of Capital & Depreciation	Transmission Costs
Tauranga	0-41kVA	32.9%	40.4%	23.6%
	42-299kVA	3.5%	6.7%	3.7%
	300-1499kVA	5.1%	5.1%	6.6%
	1500kVA+	6.5%	2.6%	7.7%
Valley	0-41kVA	35.2%	34.7%	26.8%
	42-299kVA	3.9%	4.5%	3.5%
	300-1499kVA	2.5%	2.1%	2.9%
	1500kVA+	10.4%	4.0%	25.2%
Total		**100%**	**100%**	**100%**

Table 19: Cost components recovered from Eastern region customer groups

Price Zone	Customer Group	ICPs	Revenue required:			
			Operating Costs ($000)	Cost of Capital & Depreciation ($000)	Transmission Costs ($000)	Total ($000)
Tauranga	0-41kVA	91,584	$16,422	$43,351	$12,049	$71,822
	42-299kVA	883	$1,744	$7,153	$1,868	$10,765
	300-1499kVA+	233	$2,557	$5,442	$3,379	$11,378
	1500kVA+	38	$3,224	$2,802	$3,938	$9,964
Valley	0-41kVA	74,680	$17,567	$37,174	$13,673	$68,414
	42-299kVA	599	$1,943	$4,796	$1,760	$8,499
	300-1499kVA	90	$1,250	$2,290	$1,478	$5,018
	1500kVA+	30	$5,194	$4,253	$12,851	$22,298
Total		**168,137**	**$49,901**	**$107,261**	**$50,996**	**$208,158**

For the Western region the table below sets out the allocations of costs to customer groups and zones, with the following table showing the resulting cost values.

Table 20: Cost allocations to Western region customer groups

Customer Group	Price Zone	Allocator For: Operating Costs	Cost of Capital & Depreciation	Transmission Costs
E1 (up to 100 kVA)	A	56.6%	51.5%	44.9%
	B	24.4%	35.0%	25.0%
E100 (101 – 300 kVA)		3.4%	3.6%	3.9%
W50 (301 kVA+)		8.0%	7.1%	11.2%
SPECIAL (1500 kVA+)		7.6%	2.8%	15.0%
Total		**100%**	**100%**	**100%**

Table 21: Total costs and components to be recovered from Western region customer groups

Customer Group	Price Zone	ICPs	Revenue required for: Operating Costs ($000)	Cost of Capital & Depreciation ($000)	Transmission Costs ($000)	Total ($000)
E1 (up to 100 kVA)	A	124,467	$31,431	$60,014	$21,120	$112,565
	B	55,597	$13,573	$40,695	$11,795	$66,063
E100 (101 – 300 kVA)		287	$1,902	$4,226	$1,813	$7,941
W50 (301 kVA+)		233	$4,457	$8,288	$5,294	$18,039
SPECIAL (1500 kVA+)		57	$4,201	$3,237	$7,074	$14,512
Total		**180,641**	**$55,564**	**$116,460**	**$47,096**	**$219,120**

DIRECTOR CERTIFICATION

Director's Certificate for the
2024 Electricity Pricing Methodology
Certification of Year-beginning Disclosure

We, Paul Callow and John Loughlin,

being Directors of Powerco certify that, having made all reasonable enquiry, to the best of our knowledge:

(a) the following attached information of Powerco prepared for the purposes of clauses 2.4.1-2.4.5 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
23.03.2023	23.03.2023
Date	Date