Methodology for deriving delivery prices

For prices applying from 1 April 2025

Issued 28 February 2025

We are pleased to present our Pricing Methodology Disclosure for prices effective 1 April 2025 to 31 March 2026 (the Pricing Methodology).

Purpose Statement

The purpose of this Pricing Methodology is to outline the approach used in setting our prices for electricity distribution lines services effective from 1 April 2025 to 31 March 2026 (the pricing year).

Before 1 April each year, we publish our Pricing Methodology, as is required by section 2.4, Pricing and Related Information, of the Electricity Distribution Information Disclosure (amendments related to IM Review 2023) Amendment Determination 2024 [2024] NZCC 31 (the ID Determination).

Our goal, every pricing year, is to set prices that signal the efficient use of our electricity distribution network (the network) for the long-term benefit of consumers. We signal the efficient use of our network through prices that reflect our costs to serve, and signal future investments needed on our network. Efficient pricing is particularly important as New Zealand embarks on its journey to be Net Zero Carbon by 2050.

Our pricing approach

Our pricing objective is to strike the right balance between the prices consumers pay and the provision of a reliable and resilient electricity supply that meets the needs and expectations of our central Canterbury community. Like roads, electricity networks have limited capacity and our 'rush hour' typically occurs on very cold winter mornings and evenings. Our priority is to ensure our network can sustain these demand peaks, even though they are typically only for short periods of time.

We have options as to how we meet peak demand. One option is to increase our network's capacity, much like making the roads bigger to handle an increased volume of traffic. This option, however, is expensive and would require increases in prices to cover the expansion cost. A second option is to actively promote mechanisms such as ripple control, through consumers taking up controlled prices or responding to control signals, whereby congestion on the network can be alleviated during periods of high or 'peak' electrical demand by shifting some consumption to an off-peak period.

We prefer the second option as this is the least cost option and keeps prices and services at levels our consumers expect. Accordingly, we use 'price signals' — charging higher prices during periods of high electricity demand and lower prices during low demand periods — to support and reward consumers managing their use in this way. Ways in which consumers do this include:

- Having hot water cylinders peak load controlled, which means hot water load can be switched off and on by us
- Heating hot water only at night
- Investing in more efficient forms of heating such as heat pumps, which produce much more heat output for the same electrical input
- Moving consumption to a different time of day, or reducing the level of consumption when signalled

Orion

Peak and off-peak pricing

Determining the peak periods price differential is complicated. Some parts of our network cost more than others, and different parts are used to deliver electricity to more than 229,000 individual consumer connections. Individual consumer pricing is simply not feasible for all connections.

To recognise the key differences in the usage and cost of our network, we separate consumer connections into various connection categories:

- Residential and small business connections – where electricity use peaks in winter.
- Major customer and embedded network connections – businesses that are large electricity consumers or embedded networks.
- Irrigation connections – for farms with significant irrigation requirements.
- Street lighting connections – for private and publicly owned dedicated lighting connections supplied from a separate lighting network.
- Large capacity connections – for very large businesses with significant load for which we negotiate an individual price due to their size and impact on the local network.

More detail on how we apply our prices and how the chargeable quantities are calculated for each connection category, can be found in our Pricing Policy document, which is available on our website.[1]

[1] https://www.oriongroup.co.nz/our-story/pricing

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Glossary

Abbreviation / Term	Definition or description
2025/26 Disclosure of Prices	Orion New Zealand Disclosure of Prices
Annual Price Setting Compliance Statement	Discloses how much revenue a network can collect and demonstrates that forecast prices are set at a level to collect that revenue
Capacity	The maximum amount of energy that a part of the network is able to carry at any point in time
CER	Consumer Energy Resources
Commerce Commission	New Zealand Commerce Commission
Consumer	A person, residential or business, that uses electricity or acquires electricity lines services
Consumer group	The category of consumer used by the Electricity Distribution Business (distributor's) for the purpose of setting prices
Controlled load	An amount of electrical load which a consumer makes available to the distributor's load control system to turn off during periods of network congestion or to assist in restoring supply
CPI	Consumer Price Index inflation
CPP	The Commerce Commission sets a price-quality path for each regulated lines company – a price path is the maximum total revenue a lines company can recover from its consumers and the quality path is the minimum level of quality of service that it must provide. A customised price path (CPP) is a unique price-path used to deliver a specific programme of work
Delivery price	The total delivery price for both distribution and transmission services (also known as lines charges)
Demand	Maximum amount of energy demanded from the network at any given time
DER	Distributed Energy Resources
Distributed generator	Any person who owns or operates equipment that is connected to our distribution network, including through a consumer installation, which is capable of injecting electricity into the network

Distribution Network	A distribution network is the network of equipment that carries electricity from the high voltage transmission grid to industrial, commercial, and domestic users
Distribution pricing practice note	2022 distribution pricing practice note 2nd edition provides guidelines to help distributors interpret and apply the distribution pricing principles. This can be found on the Electricity Authority's website
DPP	The Commerce Commission sets a price-quality path for each regulated lines company – a price path is the maximum total revenue a lines company can recover from its consumers and the quality path is the minimum level of quality of service that it must provide. A default price path (DPP) is a low cost, standard method of calculating the price-quality path for lines company's not on a CPP.
DPP Determination 2025	Electricity Distribution Services Default Price-Quality Path Determination 2025, [2024] NZCC 28 – 20 November 2024
Electricity Authority	The Electricity Authority is an independent Crown entity responsible for the efficient operation of the New Zealand electricity market. It is the electricity market regulator
Electricity distribution services	Electricity distribution services are the conveyance of electricity on lines from the transmission GXP to consumers ICPs
EV	Electric Vehicle
Flexibility services	Services which use consumer smart devices to move electricity demand away from congested periods on the network
GXP	A point of supply to [our] distribution network from Transpower's national transmission grid
HV	High Voltage – equipment or supplies at voltages of 11kV, 22kV or 33kV
ICP	An Installation Control Point (ICP) is a physical point of connection on a local network or an embedded network that the distributor nominates as the point at which a retailer will be deemed to supply electricity to a consumer
ID Determination	Electricity Distribution Information Disclosure Determination (amendments related to IM Review 2023) Amendment Determination 2024, [2024] NZCC 31 — 27 November 2024
IM Determination	Electricity Distribution Services Input Methodologies (IM Review 2023) Amendment Determination 2023, [2023] NZCC 35 — 13 December 23

LFC Regulations	Electricity (Low Fixed Charge Price Option for Domestic Consumers) Regulation 2004 and Electricity (Low Fixed Charge Price Option for Domestic Consumers) Amendment Regulations 2021
Lines charges	Refer to Delivery price
LRMC	Long Run Marginal Costs
LV	Low Voltage – equipment of supply at a voltage of 220V single phase or [415V] three phases
Network	The electricity distribution equipment owned by us for the conveyance of electricity. Network assets include substations, lines, poles, transformers, circuit breakers, switchgear, cabling etc.
Point of connection	A point at which a consumer's fittings interconnect with the Network as described in our Network Connection Standard
Power Factor (PF)	A measure of the ratio of real power to total power of a load. The relationship between real, reactive and total power is as follows: PF= Real Power (kW)/Total Power (kVA) Total Power kVA=$(kW^2+kVAr^2)^{0.5}$
Pricing Methodology	Orion New Zealand Pricing Methodology Disclosure Document
Pricing Principles	The Electricity Authority Distribution Pricing Principles. Guidance as to how to apply these pricing principles is provided in "Distribution Pricing: Practice Note – second edition v2.2, 2022. This can be found on the Electricity Authority's website
RAB	Regulated Asset Base – is the regulated value of the distribution assets that we use to provide full line function services
Regulatory Period	A regulatory period is the period that a price quality path determination applies to; usually five years.
Regulatory Year	A regulatory year is the 12-month period from 1 April to 31 March
TPM	Transmission Pricing Methodology is the methodology and approach, set by the Electricity Authority and implemented by Transpower, to allocate transmission costs to the user of grid services, including distributor's

Orion

1. Introduction

1.1 Who is Orion New Zealand Limited

We own and operate the electricity distribution infrastructure in central Canterbury, including Ōtautahi Christchurch city and Selwyn District. Our network is rural and urban and extends over 8,000 square kilometres from the Waimakariri River in the north to the Rakaia Rivers in the south: from the Canterbury coast to Arthur's Pass. We deliver electricity to more than 229,000 homes and businesses and are New Zealand's third largest electricity distributor.

New Zealand's South Island

We convey electricity across our network of distribution assets to consumers. We do not buy or sell electricity; we deliver it to homes and business who are the customers of the electricity retailers operating in our area. Electricity retailers, in turn, include our charges in the electricity bills to their customers. Our delivery charges amount to approximately 27% of an average household's electricity bill.[2]

Our network is entirely within the boundaries of the two local councils: Christchurch City Council and Selwyn District Council. We are owned by these councils with Christchurch City Council holding 89.3% and Selwyn District Council 10.7% of the shares respectively.

1.2 Contributing to New Zealand's decarbonised future

We are committed to making a positive contribution to the successful delivery of New Zealand's Net Zero future. In January 2021, He Pou a Rangi, the Climate Change Commission released its vision of a

> '…thriving, climate-resilient and low emissions Aotearoa where our children thrive.'

The ambitious report calls for a transformational and lasting change across society, with a strong economic focus on reducing emission at the source. The Climate Change Commission considers that transport and industrial heat electrification will significantly contribute to New Zealand realising its carbon zero targets by 2050.

Transpower's long-term strategic plan Whakamana i te Mauri Hiko predicts that demand for electricity could double by 2050. If this assumption is proven, we could see an additional 114 megawatts of load added to our network over the next 25 years. This load growth is substantial and represents significant challenges and potential opportunities. Not least of all, the need to spend capital upfront to offset future security of supply risk with no guaranteed return on investment, i.e., the need to install additional capacity in advance of its utilisation.

We are committed to managing and operating our network to deliver electricity safely, resiliently and reliably so that it meets consumers' expectations now and in a decarbonised future. Cost reflective pricing gives us the foundation for success in our commitment to support New Zealand's decarbonised future by signalling the impact of network use on consumers today and in the future.

[2] More information about the components of your power bill can be found on the Electricity Network Aotearoa website.

2. Our Network Characteristics

Pricing and asset management investments are inextricably linked and somewhat symbiotic. Pricing provides signals that inform consumer behaviour, influencing network utilisation, and signalling constraints on the network revealing the potential for future infrastructure investment. Infrastructure investment is a key cost driver and operating expenditure, over time, are reflected in the prices consumers pay, and the quality of supply they receive.

In addition to our price signalling, with a particular focus on price-quality trade-offs we look to stakeholder consultation and harnessing constraint information that is undertaken as part of our asset management plan (AMP) process. Our AMP provides detailed information on the constraint and capacity status of our network from the eight grid exit points (GXP) down to low voltage (LV) network level.

To meet our future infrastructure investment challenges, we are implementing initiatives that increase our understanding of the network. We are investing in systems that fully utilise the data sources at our disposal thereby optimising short and long-term decision making, planning, and operation of our network. Enabling us to deliver electricity distribution services that are reliable and affordable to the long-term benefit of our consumers and central Canterbury.

Like roads, electricity networks have ‘rush hours’ where loading levels peak and capacity is heavily utilised. One solution to cope with these relatively short periods of high loading is to expand our network's capacity, much like making roads bigger to handle more traffic. However, building this additional capacity could be more expensive than other alternatives. To ensure our network investments represent good value for money, we explore other, more least cost alternatives, optimising existing asset utilisation before investing in traditional reinforcement of our network. These may be to:

- influence or control demand using flexibility, load management, and smart network solutions which can benefit consumers through more efficient network utilisation and therefore price
- optimise the existing network configuration and enable the measured release of capacity through switching
- other forms of demand response.

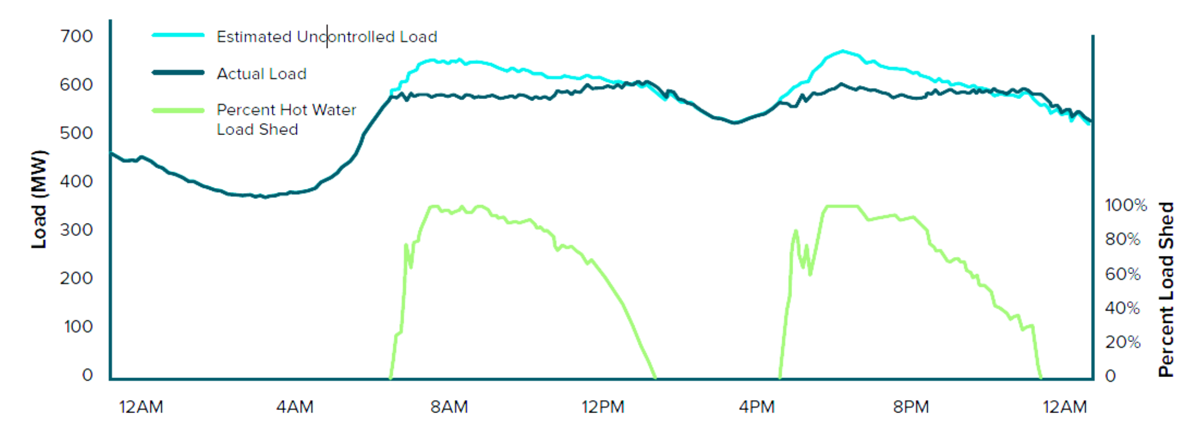
2.1 Load management

Our load management system allows us to control non-essential customer loads, such as hot water and irrigation. Enabling load deferral during peak times, reducing the need for asset investment. The load management system also provides a means to shed non-essential load during system contingencies, helping us maintain essential customer loads during such events.

The load management system comprises a range of hardware and software platforms and remains an integral part of our distribution system. In 2023, we upgraded our load management software and integrated it within our ADMS[3] system. Our investment plan for this asset class includes asset management of the hardware and software of the USI load management master station.

Load management systems support our asset management objectives by minimising peak load using deferrable load control to improve the efficiency, reliability, and sustainability of our distribution network. Figure 1 gives an example of a winter peak day demand profile shows the hot water load that was shed corresponding with peak periods.

Figure 1: *Example of a winter peak day demand profile*



Note: uncontrolled load is our estimate of the loading levels that would have occurred if we had not controlled load.

The objectives for our load management system are to—

- implement load shedding or demand response plans to lower peak demand during high-load periods, reducing network investment requirements
- optimise network asset usage by effectively managing loads, prolonging the lifespan of equipment, and minimising the need for costly infrastructure upgrades
- contribute towards SAIDI and SAIFI targets through load reduction during critical load periods by reducing the likelihood of power outages
- support continual automation to manage aggregated load to a limit and control existing ripple plant accordingly
- ensure compliance with regulatory standards and mandates related to load management, grid operation, and energy efficiency.

Currently, the primary mechanism used to facilitate load management on our network is through ripple control relays. We use ripple control to manage load in two ways.

- Peak hot water cylinder control—when network loading is high, usually on the colder winter weekday mornings and evenings, we can temporarily turn off hot water heating

[3] Automated distribution management system

to reduce peak demand. Enabling consumers to take advantage of cheaper retail pricing plans and contributes approximately 50MW of peak load deferment.

- Fixed time control—employ fixed time control to permanently shift load away from periods of peak demand and to also enable customers to take advantage of the lower electricity costs at other times of the day e.g., nights or lower cost Time-of-Use price periods. Fixed time control is mainly applied to larger hot water cylinders and contributes an estimated 75MW peak reduction.

In the future, ripple control technology is likely to be displaced by alternative systems such as smart appliances or meters responding to signalling over cellular or fibre telecommunications infrastructure.

2.2 Drivers of growth on our network

Our network feeds both high density Christchurch city loads and diverse rural loads on the Canterbury Plains and Banks Peninsula. Growth in electricity consumption in Christchurch and Banks Peninsula has historically matched growth in population, including the holiday population for Banks Peninsula however we have experienced growth higher than this in recent years. Peak electricity consumption growth on the Canterbury Plains has been driven by changes in land use rather than population growth.

Changes in Technology and customer behaviour, the drive to decarbonise, and recent housing intensification, mean forecasting growth in peak network demand, and where the growth will occur, has more facets to it. As most of these facets carry uncertainties, accurate forecasting of peak future demand is more difficult. We are now incorporating more sophisticated scenario planning, where we attempt to predict the many possible paths for demand growth and make asset investment decisions based on least regret actions or best predicted scenarios.

Network development is primarily driven by growth in peak demand, along with energy conveyed in respect of local renewable generation. The peak demand capability of our network is defined by network component capacities. For this reason, we concentrate on forecasting peak demand across all levels of our network rather than energy usage.

To support some of the growth we see, we have planned significant projects which we describe in more detail in our AMP.

2.3 Our network maximum demand

Maximum demand is the major driver of investment in our network so it's important for us to be as accurate as possible. The measure can be volatile and normally varies by up to 10% depending on winter weather.

Our network maximum half hour demand, based on load through the Transpower GXPs, for the 2024 winter period was 677MW during the peak that occurred on 20 August 2024, up 17MW from the previous year.

In the medium-term maximum network demand is influenced by factors such as underlying population trends, new customers joining the network, growth in the commercial/ industrial sector, changes in rural land use, climate changes and changes in customer behaviour. Many things influence changes in customer energy consumption which are hard to predict.

2.3.1 What issues do we take account of when planning our network?

Some of the emerging technologies we need to consider when we do are our network planning include—

Electric vehicles—there are several uncertainties with EVs including uptake rates, what proportion of drivers will charge at home or at public charging facilities and when, the diversity of home charging and what size charger will be used.

Customer actions—how consumers will respond to signals of high-cost power or high CO^2 emissions are unknown. A focus on decarbonisation could lead to improved home insulation, greater appliance efficiency, and consumers responding to reduce peak load.

Coal boiler conversions—Government from time to time introduce initiatives for business to move away from coal for industrial processes and heating. We have engaged with boiler users to gain insight into their decarbonisation plans. The absence or presence of Government incentives has an impact on the rate of conversion.

Solar photovoltaics—the future uptake rate, and size of solar installations is uncertain.

Batteries—battery uptake rates remain uncertain, as does knowledge of how our consumers will use batteries. Consumers may discharge batteries at expensive evening peak times, and recharge the batteries at cheaper times, or may discharge their batteries when they get up in the morning and through the day – meaning evening electricity usage may still be from the grid.

2.3.2 We have developed demand scenarios

Given the range of impacts the emerging technologies above will bring for the energy sector, we can no longer rely only on maximum demand forecasts based primarily on historical growth. We have moved to scenario-based demand forecasting:

Business as usual—an extrapolation of existing electrification trends, in a low growth world. Low change in technology uptake results in low economic growth and high climate change impact.

Progress—where electrification and change in consumer behaviour accelerates but does not result in full transition of the energy sector by 2050. There is some increased uptake of new technology and optimisation with medium economic and population growth.

System transition—a centrally led transition of the energy sector is achieved through high uptake of new technology, but minimal shift in consumer engagement in the energy sector. Economic growth and population growth are medium. Climate change impacts are towards best case scenarios.

Consumer and place-based transition—where consumer and place-based optimisation combined with technology change achieves energy sector transition. Climate change impacts are towards best case scenario.

Central Scenario—high growth across the region, while electrification doesn't accelerate considerably until after 2035. The scenario assumes some optimisation of charging demand and place-based optimisation but low levels of EDB controlled flexibility. The Central scenario is the scenario we use for asset management planning, as our best / least regrets view of load growth over the next 10 years.

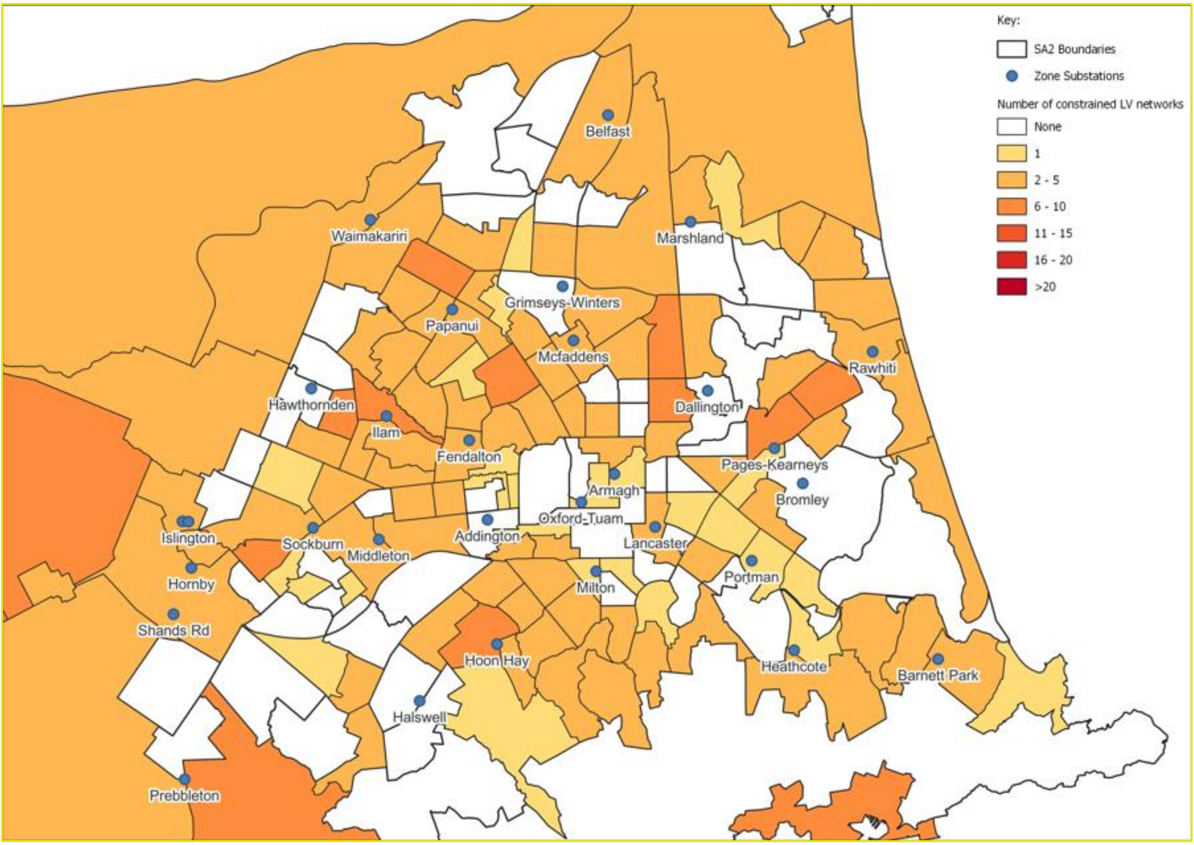
The outputs of the above scenario’s inform potential risk and what drives the differences between the scenarios. The modelling shows system peak demand growth between 10% and 42% over the next 10-year planning period. Network wide peak demand is an indicator of the load growth we expect to see on the network. Table 1 lists the scenario demand assumptions that apply to each scenario.

Table 1: Scenario demand assumptions 2034-2050

	2034			2050		
	Maximum demand (MW)	**Growth (MW)**	**% Change**	**Maximum demand (MW)**	**Growth (MW)**	**% Change**
Business as Usual	723	67	10%	839	183	28%
Progress	869	196	29%	1196	523	78%
System transition	959	285	42%	1381	707	105%
Consumer and place-based transition	840	166	25%	1056	383	57%
Central Scenario	863	238	35%	1153	479	71%

Different areas of the network and assets on the network will see load growth differently between timing and varying levels of existing capacity. Figure 2 shows the projected low voltage urban network constraints for the disclosure year.

Figure 2: Projected low voltage urban network constraints



2.4 Developing our LV capability

Historically, LV networks were planned for reasonably stable passive household loads with one-way power flow. However, more consumers are adopting technologies such as electric vehicles (EVs) which can place significant additional demand on a street's LV system. Given our LV network supplies mostly residential consumers, developing the visibility and capability of these networks is becoming increasingly important to efficiently manage our networks and facilitate consumer choice. We are doing this by:

- Leveraging and LV monitor data to create improved visibility of our assets and activity on our network, particularly Distributed Energy Resources (DER) and Low Carbon Technologies (LTC).
- Leveraging analytics tools to derive power system insights such as system constraints, network performance improvements and efficiency through optimal investment.
- Developing improved forecasting and modelling techniques to increase accuracy of the LV level.
- Investigating options for unlocking latent capacity in our network which becomes available using improved visibility, smart technology, and non-traditional solutions.

These initiatives will develop our LV networks and help us to:

- Provide information to guide our operational, planning and investment activities.
- Facilitate customer choice by better-enabling customers to charge batteries during off-peak times and potentially export power into our network at peak times, thereby lowering their net cost of electricity.
- Improve customer service through real-time identification and location of faults.
- Identify poor performing feeders and quality of service to individual customers, which will then allow us to target actions to improve customer experience.
- Reduce capital and operational costs by early warning of power quality problems, such as phase imbalance.
- Enhance safety as real- or near-time monitoring provides measurements which will better inform us of what is live, de-energised, and outside of regulatory limits.
- Display constraints in our network online, enabling others to participate in developing solutions.
- Ensure we can host increasing DER and LCT connections while maintaining the required network safety, stability and resilience in an efficient and cost-effective way.
- Maximise the two-way throughput of energy across our network.

3. Our pricing aims and objectives

We aim to set prices that are cost-reflective, effective, and appropriate. Each pricing year, we assess our prices against the Authority's measure of cost-reflective pricing to ensure that:

- we signal the economic cost to serve on our network; and
- where a revenue shortfall occurs, we recover the shortfall in a way that least distorts network use.

With these aims in mind, we set prices to:

- establish a fair range of changes,

- allocate our cost to serve fairly between connection categories,
- appropriately recover our pass-through costs (i.e., rates, levies and transmission charges[4]) and recoverable costs (i.e., incentives, penalties and rewards),
- provide appropriate demand-based pricing signals, when necessary,
- avoid bill shock where possible by having a pricing approach that is certain, transparent, and understandable,
- offer pricing that, is comparable in form to other electricity distributors and
- be consistent with the intent of the Pricing Principles.

In delivering on our aims and objectives, our pricing approach is subject to inherent limitations, including:

- the need to comply with regulatory requirements relating to fixed daily charges under the current low user fixed charge regulations and
- a lack of ability to control how prices are passed onto consumers by their respective electricity retailers.

Despite the inherent limitations faced, we are committed to evolving our pricing approach to better meet the Pricing Principles and have used the Authority's Practice Note to guide our transitional journey.

3.1 Three priorities of our long-term pricing strategy

Our pricing objective acknowledges our current position and our goals focusing on three long-term strategic priorities—

1. Cost Recovery and Reflectivity—prices must recover efficient supply costs from each consumer segment, reflecting cost drivers.
2. Price Reform Enablement—establish pricing systems, data, and processes that:
    - support efficient price structures
    - empower consumers to react to price signals.
3. Price Signalling and Behavioural Response—prices should be tailored to consumer type based on their response capability and cost-benefit opportunities. Our prices should:
    - send actionable signals
    - promote efficient network use amid increasing electrification and bidirectional energy flows
    - foster a flexible services market
    - utilise utility-mode control where oversight and the scale of benefits incentivise participation.

[4] In its December 2023 input methodology decision, the Commerce Commission reclassified transmission-related recoverable costs as pass-through costs

Figure 3: Our Pricing strategy and roadmap

More information about our pricing strategy can be found in Appendix E of this Pricing Methodology.

4. Implementing future pricing

We develop and maintain our prices to support our group purpose:

powering a cleaner and brighter future with our community

Against this purpose we have identified focus areas important to our purpose delivery, and within this framework we have identified that the key initiatives that our pricing can support are:

1. Facilitating decarbonisation and hosting capacity at lowest cost, and
2. Investing to maintain a safe reliable, resilient network at lowest total lifecycle cost.

Building on these two initiatives—

- The structure of our pricing influences customer behaviour relating to use of our infrastructure and the consequent investment needed, the adoption and sharing of renewable energy resources, the electrification of transport and process heat, and the level of non-renewable generation that is needed at times of peak consumption.
- We recognise the impact that our pricing and pricing changes has on vulnerable customers (including those in energy hardship) who do not have the resources to cope with change or adapt their behaviour. Alongside our pricing transition, we are seeking alternative approaches that might provide targeted assistance for vulnerable customers and more broadly look at ways to optimise network use to manage the cost impact, of the drive to decarbonise.

Alongside these initiatives we also have a range of practical, economic, regulatory and equitability considerations to include. There is often a trade-off between these various considerations.

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4.1 Cost-reflective pricing

Cost-reflective prices are considered fairer because consumers are charged based on how and when they use the network. Peak and off-peak rates better reflect the costs of distributing electricity on our network at different times of the day and year. Prices that reflect these time-based costs allow consumers to make better decisions about how to manage their electricity consumption, enabling them to save on their bills.

When consumers make small changes to how they use the network, this can help to reduce peak demand. Over time, this will help to reduce how much additional investment is required to deliver a reliable service, helping to keep network costs down for all consumers. Cost-reflective prices result in lower prices in the middle of the day during 11am-5pm when demand for electricity and use of the network is low. Conversely, there will be higher prices in the mornings and evening on weekdays from 7am – 11am and 5pm-10pm when the demand for electricity is high, and the network is at its busiest.

4.2 Decarbonisation

The Climate Change Commission, Ministry for Environment and others have identified that electrification of our transport fleet provides the greatest opportunity and least cost means for our community to decarbonise. A resilient electricity supply with stable pricing will facilitate this transition and providing attractive off-peak charging options will accelerate the transition and improve the efficient use of our network.

Our pricing for industrial customers can also support the electrification of process heat.

Looking further forward, we aim to help consumers share their local renewable energy resources and utilise the energy stored in batteries (be they standalone or electric vehicle (EV) batteries via vehicle-to-grid (V2G)) to stabilise the energy system.

Traditional volume-based pricing approaches can discourage electrification of transport and process heat, and act as a barrier to consumers using our network to share their local renewable resources. Volume-based pricing approaches also encourages customers to make inefficient investments in technology, including expensive forms of renewable generation and devices that avoid sharing of energy resources (such as batteries and hot water diverters). Our strategy includes a transition away from the current level of volume-based pricing.

4.3 Affordability

We recognise the vulnerable within our community, those that do not have the resources to accommodate additional costs, nor to adapt their usage to mitigate the additional cost. We observe that more than 20% of our residential consumers live in areas with a high deprivation index. Within this group, we have higher usage customers that may live in energy hardship (spending more than 10% of their income on electricity), but also a large proportion (approximately 70%) with lower-than-average usage.

Any change in pricing structure creates winners and losers. There is “collateral damage” when changes affect customers that are not contributing to an area of concern and/or are not able to respond.

Of particular concern, we have identified that a greater proportion of our vulnerable customers sit within the lower consumption bands. While a shift away from volume-based pricing will provide lower cost outcomes in the long term, it also shifts more of the cost burden onto these consumers.

The main tools to mitigate this impact is to implement a staged transition, spreading the change over several years and to provide pricing options throughout the day. This provides more opportunity for vulnerable consumers to adapt and for support mechanisms to adjust[5], and for consumers to tailor usage at lower cost times.

We also intend to look for ways we can provide targeted relief to customers in need, and we are supporting the industry initiative to set up a support fund that operates alongside the removal of the low fixed charge regulations.

4.4 Economic considerations

In terms of the structure of our pricing, we aim to ensure that our pricing is economically efficient, which means that:

- consumers choosing to use our network should face the appropriate cost of that decision and be incentivised to weigh up the value of the service and the cost of alternatives, and consequently
- investments in our network over time will be at an appropriate level and in the interest of consumers.

In our 2023 Pricing Methodology, our 5-year Pricing Strategy outlined the problem definition and flagged our intention to transition fixed prices to an installed capacity basis. Fixed charges would be at an installation level based on installed capacity.

In this pricing year, the third year of our transitional journey, we have made further steps to transition consumers to a capacity-based pricing approach. This pricing year we have transitioned away from GXP billing to ICP billing and introduced a new Residential standard user price category to support the phase-out of the low user charge regulations. We have not, unfortunately, made progress on moving to fixed charges based on an installed capacity basis.

Our long-term vision is to have our fixed daily charges based on installed capacity and variable charges to be the marginal price of electricity (i.e., the amount needed to recover the residual revenue not collected through fixed charges). The five-year transition of the low fixed charge regulations means we cannot evolve our pricing approach in a single pricing year.

4.5 Even-handedness and practical considerations

Through our pricing we take account of the need for even-handedness and practicality in determining customer groupings (categories), cost allocations and the structure of our pricing.

Specifically, we:

- apply price averaging over connection categories, because it is generally not practical to single out individual connections for cost-specific delivery pricing. However, where it is practical, we do allocate assets and associated costs only to the connections or connection categories that use them.
- recognise that all consumers should share in the benefits of greater utilisation of shared assets and other enhanced economies of scale (new customers are not gifted existing capacity, instead

[5] Such as those initiatives highlighted in the Energy Hardship Expert Panel report on Energy Hardship: The challenges and a way forward https://www.mbie.govt.nz/dmsdocument/27831-energy-hardship-the-challenges-and-a-way-forward-energy-hardship-expert-panel-report-to-minister-pdf

the costs of significant upgrades are spread across new and existing consumers that share in their use).
- recognise that consumers change their demand behaviour over time, and it is important that we provide compelling and consistent pricing incentives aimed at maximising the efficient utilisation of our assets.
- seek to make our price signals effective by balancing strong price signals with easily understood application and measurement,
- treat connections with similar electrical attributes consistently,
- set prices that are the same for all retailers, providing a "level playing field" to promote retail competition.

4.6 Our 1 April 2027 pricing goals

Progressively increase the proportion of fixed charge revenue recovered from consumers to achieve an equitable fixed / variable split:

- Work through the phase-out of the low fixed charge regulations and incrementally increase the proportion of fixed charge revenue recovered from residential connections.
- Introduce new price categories for small and medium enterprises (SME)[6] and incrementally increase the proportion of fixed revenue recovered from them.
- Remove our fixed peak charge and convert to variable Peak TOU charges[7]
- Introduce controlled and uncontrolled charges[8]

Progressively rebalance how variable components are recovered:

- Introduce more targeted TOU variable pricing for residential and SME
- Introduce a demand charge
- Explore Distribution Energy Resources ("DER") and Customer Energy Resources ("CER") on our network around dynamic pricing and operating envelopes
- Move away from GXP pricing and billing to ICP pricing and billing[9].

Transparently manage our key transition constraints by:

- complying with the Electricity Authority's distribution pricing principles and guidance on these
- administering the phase-out of the low fixed charge price regulation
- managing bill impacts of the default price path for the 2025-26 to 2029-30 pricing period
- retaining transmission pass through as regulated
- scaling of new billing system functionality and retailer interfaces for ICP 30-minute interval data
- accommodating legacy accumulation meters out to 2030 which require legacy prices using our existing GXP deemed load profiles

[6] We completed this step in our 2023 pricing

[7] We transitioned this in our 2023 pricing and the fixed peak charge will be removed in our 2024 pricing

[8] We introduced controlled and uncontrolled pricing in our 2024 pricing

[9] We move to ICP based billing at 1 April 2025

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- supporting our asset management strategy (including demand response controls) and investment plans as these evolve.

5. Changes made for 1 April 2025

We have made several material changes to our prices effective 1 April 2025. The changes we have made to our pricing approach are listed in Table 2.

Table 2: Summary of the changes made to our pricing approach effective 1 April 2025

Consumer Category	Description of the changes made effective 1 April 2025
Residential Low User	The general fixed daily supply charge will increase from 60 cents to 75 cents as per the phase out of the low fixed charges. More information on the low fixed charge regulations and their phase-out can be found in Appendix B on page 76. We intend to move to a fixed installed capacity charge over time. To support a smooth transition to a fixed installed capacity charge, we will conduct a staged process, including comprehensive communication and education program for residential consumers and an audit of all current connections in the SME category. 1 April 2025, we have transitioned the fixed/variable split from 22% fixed / 78% variable split to 31% fixed / 69% variable. We were able to make this change while: • Making small immaterial changes to our pricing methodology • Avoiding perverse impacts on consumers • Remaining compliant with the low fixed charge regulations Over the coming years, we will transition the fixed / variable split towards a higher proportion of our costs recovered through a fixed charge. We will do this to the extent permissible each year under the transitional arrangements of the low fixed charges regulations and will preserve some level of price signal through variable charges.
Residential Standard User **Small - GEN (GC1)** **Medium - GEN(GC2)** **Large - GEN(GC3)**	From 1 April 2025 we have made some more gradual structure changes to better reflect Residential connection utilisation of the network. We are transitioning the fixed charge to a capacity-based charge over time. We have introduced standard residential, residential controlled and uncontrolled, and TOU variable charging. • Introduced Residential Standard User • Controlled fixed network charge (per ICP, per day) • Uncontrolled fixed network charge (per ICP, per day) • Variable network charge (peak units per kWh) • Variable network charge (shoulder units per kWh) • Variable network charge (off peak units per kWh) • Variable network charge (super off peak units per kWh) • Variable network charge (weekend units per kWh)
Two-way power flow	From 1st of April 2025 we have introduced a new price category to reflect prosumers on the network for both residential and commercial. This will attract a rebate for injection back onto the network during peak times.

Consumer Category	Description of the changes made effective 1 April 2025
	Uncontrolled fixed network charge (per ICP, per day) Variable network charge (peak units per kWh) Variable network charge (shoulder units per kWh) Variable network charge (off peak units per kWh) Variable network charge (super off-peak units per kWh) Variable network charge (weekend units per kWh) Variable network rebate (peak units per kWh)

Delivery charges effective 1 April 2025 and a comparison with the delivery charges effective 1 April 2024 is included in Appendix A.

5.1 We have decided to retain uniform pricing

We have decided to continue applying a uniform delivery charge for the foreseeable future. While we calculate locational prices and prices for both distribution and transmission, our analysis supports application of a uniform delivery charge that is indifferent of location and inclusive of both distribution and transmission prices.

We do calculate granular prices, however, applying those prices would add significant costs to billing without a discernible benefit to consumers. Accordingly, the cost versus benefit does not support us moving away from uniform delivery charges for this pricing year.

More information on our approach to setting uniform delivery charges can be found in section 10 of this Pricing Methodology.

5.2 We have taken the next steps to evolve our pricing

The context under which we set our pricing is constantly evolving. We last refreshed our pricing strategy in June 2024.

We developed our new pricing strategy with stakeholder and consumer engagement conducted in late 2023. This strategy informed our current pricing roadmap.

The Electricity Authority Te Mana Hiko has also evolved its expectations on our pricing practices, designs and evidence base. Since our 2021 pricing strategy the authority has published a practice note in 2022, progressed broad industry pricing consultation across 2023 and published open letters of its expectations in 2023 and 2024. Our new strategy also addressed the Electricity Authority's expectations, signalled through updated pricing practice notes and pricing consultations during 2022 and 2023.

Figure 4 illustrates the approach we have taken to refresh our pricing strategy, and how we intend to implement and refine it over the roadmap horizons. We have retained the horizons from our existing roadmap.

We recognise that how we transition our pricing is important to the effectiveness of our pricing strategy in realising our pricing objectives.

Our transition principles are our commitment to our consumers for how we intend to implement and refine our roadmap over time.

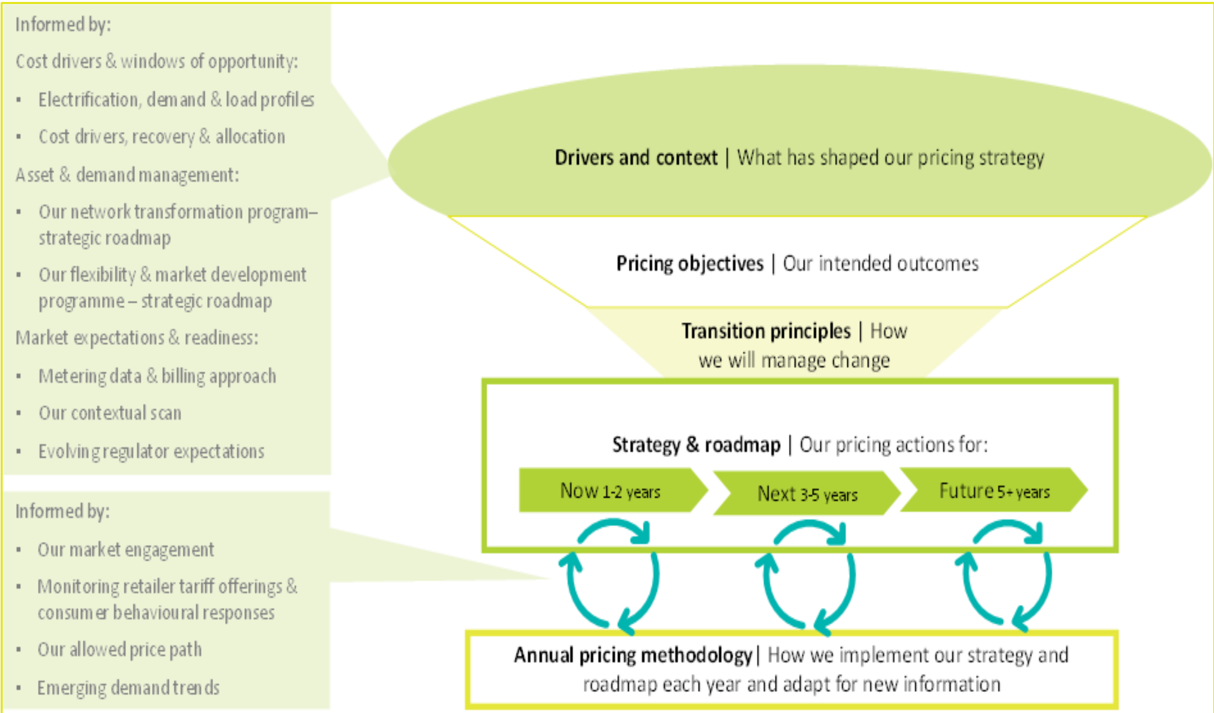
Our overarching transition principles:

Our roadmap seeks to:

- develop prices transparently and consider transaction costs, consumer impacts, and uptake incentives

- provide predictability for consumers to make investments with certainty and for retailers and aggregators to design market offers
- use the right tool for each consumer segment's required behaviours and controls, including simplicity where possible
- acknowledge the market value stacking opportunities and materiality when designing prices for cost recovery and behavioural response by understanding the interaction of our prices with the rest of the supply chain costs benefits and market signals
- ensure consumers outcomes are equitable and appropriate.

Figure 4: Our approach to reviewed pricing strategy and roadmap



Our consumer segment specific principles: We recognise that some consumers will have specific needs amid pricing transitions. Our roadmap seeks to:

- consider impacts on vulnerable consumers within our residential connection's community
- provide signals for electrification and decarbonisation, particularly for commercial and industrial connections and EV charging
- provide signals to flexibility stakeholders who can access multiple value streams to attract coordinated and two-way CER connections.

5.3 This year's pricing programme

This year's pricing program marks a significant change to our billing and engagement processes:

- We are implementing ICP pricing and billing, enabling more granular billing and alignment with consumer usage trends.

- The new granular residential pricing will allow consumers to see prices that more accurately reflect their specific energy consumption behaviours, promoting fairness and transparency.
- Differentiated Time-of-Use (TOU) variable rates are designed for different consumer segments, ensuring each group is charged according to its unique consumption profiles.
- Introducing a new price category, implementing a two-way power flow category, which promotes energy efficiency and facilitates the adoption of renewable energy sources, enabling consumers to contribute to a sustainable energy landscape.

5.4 Network Price Structure

Network prices are how consumers are charged for their network service and energy usage. We charge our network prices to retailers, who then pass them onto their consumers. These prices enable us to recover the revenue needed to build, operate and maintain our network to transport electricity to our consumers. The underlying principles to our approach to prices are outlined in Figure 5.

Figure 5: Underlying principle to our approach to pricing

Transparent Prices are simple and transparent	**Empowered** All consumers are empowered to take control of their bills and make efficient consumption and technology choices
Predictable Prices are predictable and stable over time	**Fair** Prices are reflective of consumers' network costs

We engaged with stakeholders, including end-consumers and consumer advocates in developing our pricing strategy and roadmap. We undertook formal consultations with retailers, a range of external stakeholders and other market participants, who could pool and sell energy generated and exported back to the distribution network by our consumers from rooftop solar, batteries or electric vehicles.

Efficient network pricing requires a clear and causal link between network use and the costs that exports impose. We engaged with our stakeholders on how costs could be most efficiently reflected in and impacted by prices. As a result, we consulted on introducing a two-way power flow price category that give import and export price signals. This requires an estimation of the forward-looking efficient costs, or long- run-marginal-cost (LRMC), for both imports and exports. Our estimates of LRMC include those components of forward-looking network expenditure that could be avoided through a change in the timing of consumption or generation.

For our proposed export prices, we will further consult and model the concept of a basic export level to consumers without charge, which would allow consumers to export to our network up to this level at no additional charge. This basic export level could be closely linked to the pre-existing, inherent export hosting capacity of our network and reflect the baseline level of export power flows that can be supported without the need for additional network expenditure.

5.5 Introducing the Two-way power flow price categories

This year we made the bold step of introducing two-way power flow pricing for residential and commercial consumers. Two-way prices, also known as 'prosumer prices', pertain to the rebates and charges consumers receive for returning surplus energy they generate, such as from rooftop solar panels, back to the grid. Export prices, which reflect actual costs, can enhance network utilisation, motivate more consumers to invest in new technologies, and help prevent inefficient additional investments in the network.

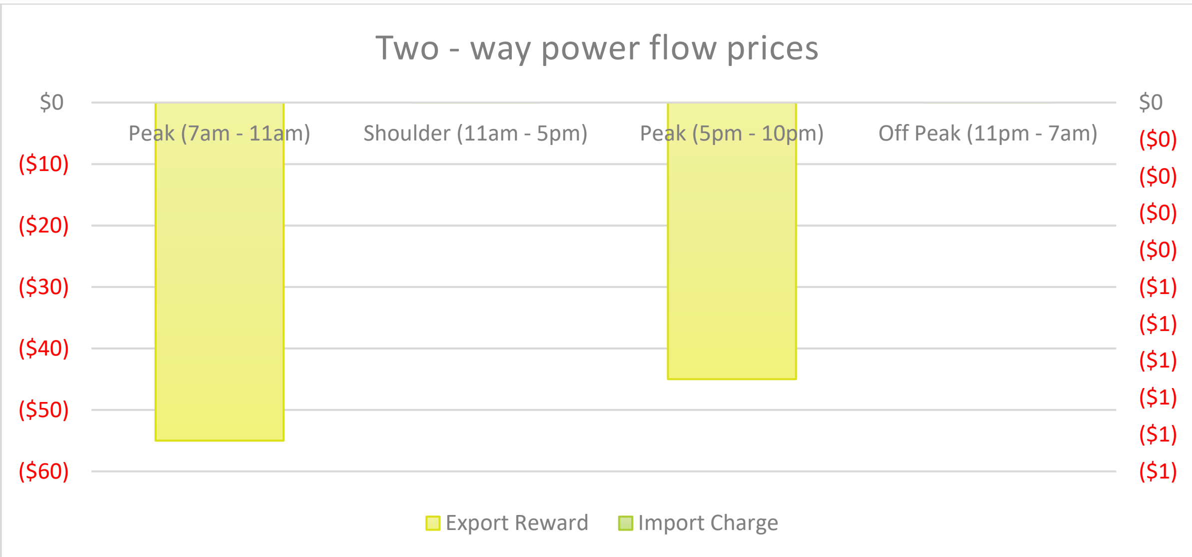
5.5.1 The two-way power flow prices are an opt-in from 1 April 2025

Eligible existing consumers can opt in to an export price starting on 1 April 2025. From 1 April 2025, new and upgrading consumers who export energy back to the grid, could opt in to the two-way price but are able to opt out if they choose.

5.5.2 Strong pricing signals to shift consumption out of the peak

We are proposing to reward consumers for exporting electricity during times of peak electricity demand on weekdays. The introduction of our new two-way power prices is intended to encourage consumers to export the excess energy they are generating for other consumers to use when it is most needed. Figure 6 shows the price signals sent through a reward when exporting during the peak and the 'sharp' price differential to encourage importing during the off-peak and shoulder and avoiding importing during the peak periods.

Figure 6: Two-way power price export reward and import charge profile



5.5.3 Why have we introduced two-way power flow pricing?

The introduction of a two-way pricing model offers several key benefits that enhance both consumer engagement and grid efficiency.

Two-way pricing is a dynamic approach that can significantly enhance the efficiency and fairness of electricity distribution. By implementing two-way pricing, we can move away from traditional volume-based pricing models and instead adopt a more flexible and responsive system. This approach allows for the adjustment of prices based on the time of use, providing clearer signals and rewards for consumers who help ease congestion during peak periods.

Figure 7 shows the consumption profiles for a prosumer with solar (dotted blue line) and standard consumer with no solar (solid green line). The trend shows that prosumers with solar while decreasing their use of the network and overall consumption, they are not doing so during the peak periods. In fact, use by prosumers and peak consumption patterns mirror that of the standard consumer and intersect at the peak (i.e., at 7:30 PM) and during the peak months (i.e., May to August). Creating what is commonly known as the duck curve.

Figure 7: Solar and no Solar consumption profiles

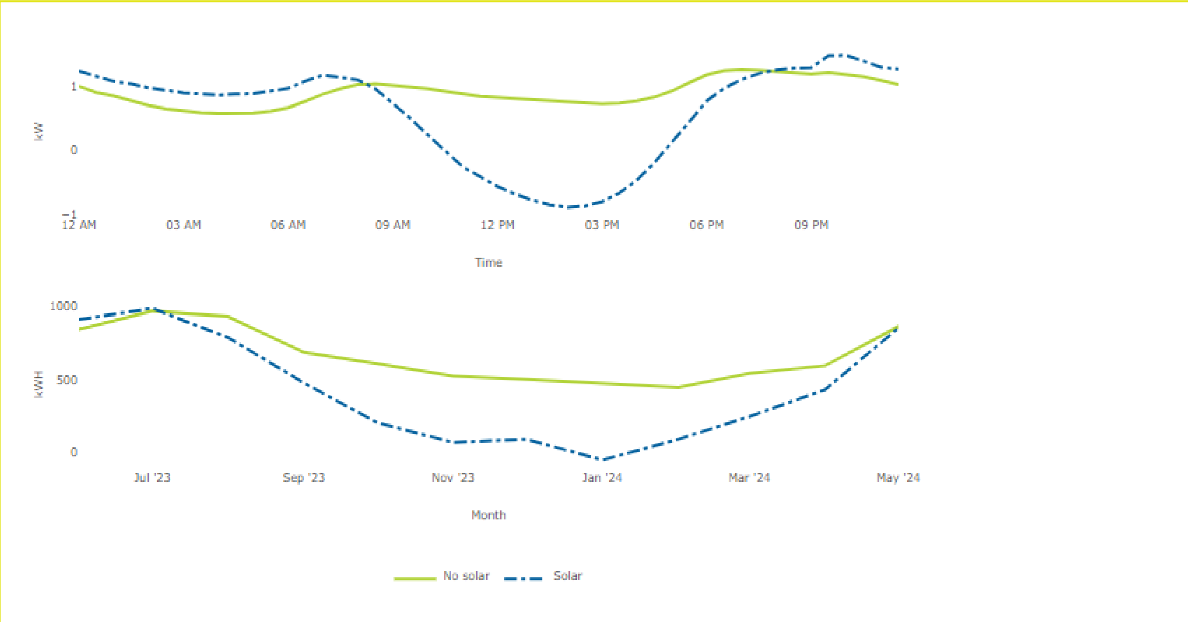
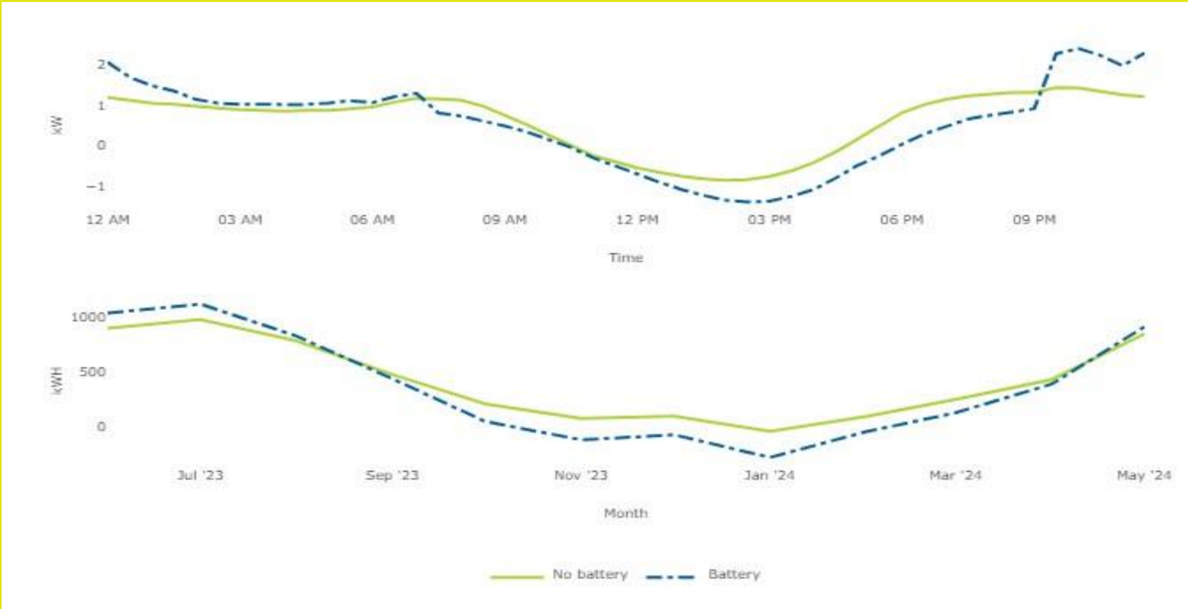


Figure 8 shows the consumption profile for a prosumer with a battery (dotted blue line) and standard consumer with no battery (solid green line). The trend shows that prosumers with batteries decrease their use of the network and consumption marginally at off peak periods. There is some lag in the utilisation of the network to the shoulder and off-peak periods and consumption in the peak months is higher than that of standard users.

Figure 8: Battery and no Battery consumption profiles



5.5.3.1 The importance to signal avoidable costs to consumers

Until now we have not sent prosumers a pricing signal that informs their use of our network. Introducing our two-way power flow price categories will enable us to signal to prosumers the costs that might be avoided or caused by additional exports, at different times of the day, in turn promoting efficient investment in DER, the efficient use of CER and this help us to ensure that we incur only efficient network costs, i.e. to make the network investments only when it is the least-cost solution.

As discussed previously, when consumer demand peaks and our network becomes constrained we are required to make additional investments in network capacity to ensure that we can continue to provide safe and reliable import services to consumers. Exports by prosumers during these periods of peak demand can help to avoid those network investments, thereby reducing the costs we need to recover from all consumers.

Signalling to prosumers, the future costs that can be avoided by exporting at peak times, using export rewards, we are then able to signal to consumers the network benefit associated with exports at peak times. A pricing signal enables consumers to evaluate whether an investment in a behind the meter battery or participation in a community battery can help lower the costs for our consumers and elicit a positive return on investment for the consumer. Signalling these benefits to consumers is an important way to harness the value of CER.

Furthermore, periods of low residential load during the day and the increased uptake of solar PV systems may be contributing to localised imbalances between consumer imports and exports from:

- high output from solar PV generators on the low voltage network; and
- lower levels of load, which have traditionally occurred during the day

Our existing prices only signal the costs of additional load during peak demand through peak charges. Providing cost reflective prices and rewards for two-way flows is an opportunity to empower choice and control over consumers energy use and harness the full network value of consumers investment in CER.

Signalling these future costs to consumers will ensure that they are only incurred if there is no other cheaper solution to managing imbalances between load and exports during off peak times. It will also mitigate the risk of inefficient underinvestment in increasing our hosting capacity.

Failing to signal to consumers the costs that can be avoided through efficient investment in CER and the efficient use of CER is likely to lead to higher future network costs, which is not in the best interests of our consumers.

5.5.3.2 Downstream economic benefits

Additionally, we believe that our two-way power flow prices will support the integration of local renewable energy resources, encouraging consumers to share these resources across the network. Promoting sustainability and reducing the overall demand on the grid, leading to a more balanced and resilient energy system.

Further, two-way power flow prices have the potential to mitigate the impact of price changes on vulnerable consumers, ensuring that the transition to a more sustainable energy system is equitable for all. Moreover, it aims to foster a more resilient energy system by encouraging demand response, where consumers adjust their energy use in real time based on pricing signals. Overall, two-way power flow pricing aligns consumer interests with grid management, promoting efficiency, sustainability, and cost-effectiveness.

5.5.4 Introducing a two-way power flow price category supports consumers energy transition strategies

Although our consumers supported the introduction of two-way pricing, they also raised concerns of penalising, considering the environmental and network benefits to which they can give effect.

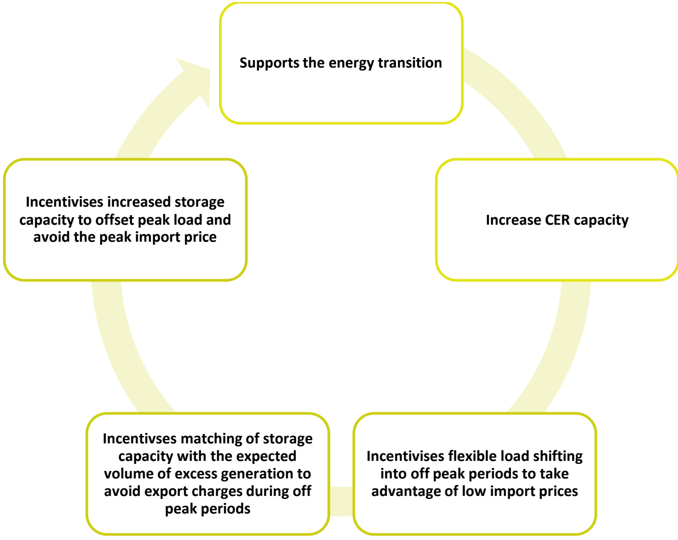
We have therefore designed our proposed two-way prices to support our consumers through the energy transition, by enabling them to utilise the value of their investments in CER and contribute to lowering our network costs, to the benefit of them and all other consumers.

Our proposed approach to two-way pricing will encourage several key consumer-led aspects of the energy transition, including:

- shifting flexible load to periods where renewable generation is most abundant
- increasing storage capacity to ensure that load that does not align with the timing of renewable supply can still be utilised by these resources; and
- increasing renewable energy generation capacity so that demand can be met

Figure 9 illustrates the role our two-way power flow price plays in supporting residential and small business consumers in the energy transition

Figure 9: Our two-way power flow prices and the energy transition



5.5.4.1 Reducing the risk of consumer impact

We are introducing the two-way power flow price category under the concept of a 'trial price' to our residential and small business consumers to better understand whether:

- consumers will respond to an export charge and import reward during peak periods by shifting load into off peak periods to reduce excess solar generation exported onto the network; and
- if the uptake of storage systems for consumers on the price increased to utilise their excess generation at the time of highest value, i.e., during the evening demand peak period.

The relative infancy of this price has limited the insights that we can draw from. However, feedback has led to a change in our proposed two-way power flow price structure to include energy based, rather than demand-based export rewards.

6. Measuring consumer Impact

We are mindful that a change in pricing approach can impact consumers differently. There is the potential that some consumers will be better off under capacity-based pricing in the short term, and some will be worse off. Over the longer term, consumers will pay their true costs to serve because prices are efficient. Efficient prices send the right signals and reduce the overall costs to serve all consumers (compared to the costs that would have arisen had inefficient prices driven up the costs to serve).

We attempt to fully mitigate perverse year-on-year outcomes as far as practicable. Otherwise, we risk sending the wrong signals to consumers and encouraging inefficient network use, thereby driving up costs. More details on our approach to smoothing prices can be found in subsection 10.4.3 of this Pricing Methodology.

The changes to this pricing year's low fixed charge regulations resulted in a 25% increase to residential consumers' fixed daily charges. We considered it fair and reasonable to start transitioning prices so that residential consumers pay more of their true cost to serve in this pricing year and avoided bill shock from a sudden and unexpected increase in price by keeping variable prices unchanged. The impact on annual charges for a typical residential connection was an increase of +$14.08 or +22%.

The impact on the average SME connection was +$381 or +22% per annum, and +$14,455 or +23% for major connections. Our impact analysis indicated that the change to a capacity-based approach impacted connections with mismatched connection capacity and usage profiles the most. This is not a perverse outcome as we intend to send a strong signal to the consumers on our network that are best placed to effect change.

SME consumers can affect their lines charges by right sizing their connection to meet their individual needs. We conducted a desktop audit of connected capacity on our network. It appears that several connections have installed capacity that is greater than their current needs. Oversized connections can be historical, i.e., due to connected load that had since been reduced when pumps, machinery, and other connected loads were replaced with newer, more energy-efficient equipment at the connection.

Any consumer who thinks they might have a larger connection than what they currently need or are likely to need in the future should consider applying to downgrade the connection. A connection downgrade could be as simple as changing the fuses and performed on request.

Our network charges make up approximately 27% of consumers' total electricity bills. The other 73% comprises electricity generation charges, retailer charges, levies and metering costs, transmission, and GST. We have no control over how retailers pass our network charges on to consumers. Questions about how the changes to our network charges will affect a consumer's total electricity bill are better directed to that consumer's electricity retailer.

7. Standard connection contracts

We supply electricity distribution services to consumers via Retailers[10] under the terms in our Default Distribution Agreement, our standard connection contract. We have 21 retailers trading on our network.

7.1 How we assign consumers to price categories

Consumers are assigned to one of ten price categories based on the consumer's utilisation of our network. The rationale and method/criteria are demonstrated in Table 3. Revenue is recovered from consumers through fixed daily charge and variable time-based prices.

Table 3: Consumer groups and network charge categories effective 1 April 2025

Consumer Group	**Fixed and Variable Charges**
Streetlighting	Fixed charge – per lamp, per day
Residential Low User	*Uncontrolled Charge* Fixed Daily Charge – per ICP, per day Weekends (Saturday and Sunday) – per kWh Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm) – per kWh Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm) – per kWh Off Peak (Mon to Fri, 10:00pm to 3:00am) – per kWh Super Off Peak (Anytime between 3:00am and 5:00am)- per kWh
Residential Standard User	
Small General Connection	
Medium General Connection	

[10] A list of retailers operating on our network can be found at https://www.oriongroup.co.nz/consumers/about-electricity/industry-structure/retailers/

Consumer Group	Fixed and Variable Charges
Large General Connection Residential Two-way Power Flow *(injection and consumption)* *Commercial Two-way Power Flow* *(injection and consumption)*	*Controlled Charges* Fixed Daily Charge – per ICP, per day Weekends (Saturday and Sunday) – per kWh Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm) – per kWh Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm) – per kWh Off Peak (Mon to Fri, 10:00pm to 3:00am) – per kWh Super Off Peak (Anytime between 3:00am and 5:00am) per kWh
Irrigation Connections	Capacity Charge – per kW, per day Power factor correction rebate – per kVAr, per day Interruptibility rebate – per kW, per day Weekends (Saturday and Sunday) – per kWh Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm) – per kWh Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm) – per kWh Off Peak (Mon to Fri, 10:00pm to 3:00am) – per kWh Super Off Peak (Anytime between 3:00am and 5:00am) per kWh
Major Customer and Embedded Network Connections	Fixed charge – per ICP, per day Fixed Charge (additional connections) – per ICP, per day Extra switches – per switch, per day 11kV Metering equipment – per ICP, per day 11kV Underground cabling – per km, per day 11kV Overhead lines – per km, per day Transformer capacity – per kVA, per day Peak charge (control period demand) – per kVA, per day Nominated maximum demand – per kVA, per day Metered maximum demand – per kVA, per day
Large Capacity Connections	Individually assessed prices advised and charged directly to the customers

8. Non – standard pricing

Non-standard pricing and individual account management is offered to industrial and large capacity connections to provide a tailored service. We offer this when the consumer's needs are unique to them, e.g., timing and scale of investment. Our approach to non-standard pricing considers consumers' individual capacity and demand to ensure, to the extent practicable, that the price is cost reflective. Refer to Appendix C for commentary about the extent to which this is consistent with the Authority's pricing principles.

8.1 Asset-based building block approach ("ABBA")

The asset-based building block approach is used to set prices for very large consumers. These are consumers that have a direct contractual relationship with us for a defined term, typically for:

- a step change upgrade or
- a new consumer connection is required that involves significant investment.

Asset-based pricing comprises the following input components:

- return on regulatory asset base, plus regulatory depreciation in period or year

- sub-transmission cost allocation of direct and indirect costs for sub-transmission asset utilisation in period of year.
- operating and maintenance costs
- tax adjustment; and
- recovery of pass-through costs and recoverable costs (e.g. transmission charges and regulator levies).

As a general guide, and subject to the considerations above, connections requiring a capacity of greater than 10 MVA in the urban area, or greater than 4 MVA in the rural area would be considered for non-standard pricing.

Consumer specific pricing applies to large capacity connections. Asset -based pricing may also apply to generation connections and special arrangement designed to mitigate the risk of uneconomic asset bypass. Each price is set individually using a building block approach as further described in Table 4.

Table 4: Summary of how we apply ABBA

Activity	**What's involved**
Measurement and forecasts of consumer demand and connections	Measurement and/or estimation of consumer's demand by historical AMD (Anytime Maximum Demand), CPD (Peak Coincident Demand) and ADL (Average Demand Level), is used to calculate asset-based prices.
Calculate value of assets	The assets used to supply the service are valued in association with the regulatory asset base (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 consumer. Upstream assets are allocated using the site's maximum demand and the demand of the section of the network (e.g., 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 consumer; this is based on our prevailing weighted average cost of capital (WACC). Depreciation is allocated based on the asset's actual depreciation during the most recent regulatory period.
Allocate maintenance costs	Maintenance costs are allocated to the relevant load groups based on the load group's regulatory asset base (RAB) relative to the applicable GXP's total RAB. These costs allocated against the assets used by each consumer, 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 usage. All our costs to serve are indirect costs except for transmission, asset-related costs, maintenance, interest, and tax.

Activity	What's involved
Allocate transmission costs	Transpower's Connection, Benefit-based, and Residual Charges are allocated to their customers' using the approaches prescribed in the Transmission Pricing Methodology (TPM). We allocate and pass-through these charges to consumers using mechanisms that reflect the TPM and the Authority's Pricing Principles and TPM pass-through guidance. The Connection charge is based on the consumer's demand, as measured by Anytime Maximum Demand (AMD) i.e., load. The Benefit-based and Residual charges are allocated based on historical usage, measured by Average Demand Level (ADL).

8.2 Non-standard connection contracts

Large capacity connections have specific non-standard contractual terms including delivery obligations and responsibilities in the event of supply interruptions. These attributes are disclosed in our *Disclosure of prescribed contracts* document which is available on our website[11]. In general, for these consumers we:

- provide uninterrupted supply security against a range of faults by maintaining duplicate supply assets,
- prioritise restoration of supply following outages, and
- maintain a "last to shed" priority for grid emergencies, and to the extent reasonably practical, not include the connections for "automatic under frequency load shedding", nor "automatic under voltage load shedding".

This supply security is greater than our standard undertakings which are set out in our "security of supply standard" in our published asset management plan. The key difference is that for a range of faults, power is off for the duration of the repair time (often up to 4 hours) under our normal security of supply standard. The higher supply security is provided for these consumers through the provision of additional back up supply assets, and this is reflected in the prices applied.

With only two consumers (15 ICPs) presently in the large capacity connection category commercial sensitivity prevents us from providing any load profile for this category. These arrangements have no direct effect on the determination of ongoing prices of these consumers.

9. Calculation of our costs to serve

9.1 Calculation of the Required Revenue

The required revenue represents the forecasted costs incurred over the pricing year. Through our prices effective 1 April 2025, we intend to recover the required revenue of $316.98 million over the pricing year. Table 5 provides a breakdown of our required revenue for the pricing year.

[11] *https://www.oriongroup.co.nz/our-story/regulatory-disclosures*

Table 5: Breakdown of our Required Revenue

Description	Amount ($'000)
Operations and Maintenance Costs	33,906
Administration and Corporate Costs	52,572
Regulatory depreciation charges	58,914
Regulatory return on investment	81,912
Transpower Charges	70,179
Regulatory Cost / Levies	10,407
Recoverable costs	4,986
Total Revenue Recovered from Prices	*312,876*
Large connection contracts	-
Other regulated income	4,100
Total required revenue	**316,976**

9.1.1 Calculation of the Operations and Maintenance Costs

Our forecast Operations and Maintenance costs for the year are $33.9 million. Table 6 provides a breakdown of our forecast operations and maintenance costs for the pricing year.

Table 6: Breakdown of our Forecast Operations and Maintenance Costs

Description	Amount ($'000)
Service Interruptions and Emergencies	9,856
Vegetation Management	4,933
Routine and Corrective Maintenance	16,032
Asset Replacement and Renewal	3,085
Total Operations and Maintenance Costs	**33,906**

9.1.2 Calculation of the Administration and Corporate Costs

Our forecast Administration and Corporate Costs for the pricing year are $52.6 million. Table 7 provides a breakdown of our forecast administration and corporate costs for the pricing year.

Table 7: Breakdown of our Forecast Administration and Corporate Costs

Description	Amount ($'000)
System Operations and Network Support	21,534
Business Support	31,038
Total Administration and Corporate Costs	**52,572**

9.1.3 Calculation of the Depreciation Charges

Our forecast Depreciation Charges for the pricing year are $58.9 million. The Depreciation Charges reflect the annual charge to the accounts for depreciation on network system assets and related fixed assets costs as communications equipment and network-related software. As per the company's management accounts, our forecast is equal to the budgeted depreciation charges for the network business between 1 April 2025 and 31 March 2026. Table 8 provides a breakdown of our forecast depreciated charges for the pricing year.

Table 8: Breakdown of our Forecast Depreciation Charges

Description	Amount ($'000)
Non-System Fixed Assets	5,000
System Fixed Assets	53,914
Total Depreciation Charges	**58,914**

9.1.4 Calculation of Transpower charges and Regulatory costs

Transpower charges are the contracted Transmission costs of the national grid operator Transpower for the pricing year. Our notified transmission charges effective 1 April 2025 to 31 March 2026 are $70.2 million. Regulatory costs / levies include amounts charged by the Authority, Commission, Ministry of Economic Development, and the Utilities Disputes scheme. Our forecast regulatory costs / levies for the pricing year are $10.4 million.

9.2 Change in Required Revenue

Our required revenue has increased by $59.2 million (or +23%) for the 1 April 2025 pricing year when compared against the prior pricing year 1 April 2024. Table 9 provides the movement in required revenue between the pricing years.

The primary causes of the increase in target revenue are an increase in—

- return on investment of +$39.6 million or (+94%)
- Transpower charges of +$10.4 million (or +17%) forecast for the 1 April 2025 pricing year.

Table 9: Movement in revenue requirement between pricing years

Description	1 April 2025 ($'000)	1 April 2024 ($'000)	Movement ($'000)	Movement Percent
Operations and Maintenance Costs	33,906	33,307	599	+2%
Administration and Corporate Costs	52,572	54,408	(1,836)	-3%
Depreciation charges	58,914	56,000	2,914	+5%
Return on Investment	81,912	42,269	39,643	+94%
Transpower charges	70,179	59,759	10,420	+17%
Rates/Levies	10,407	10,407	-	0%
Recoverable costs	4,986	1,633	3,353	+205%
Total Revenue Recovered from Prices	*312,876*	*257,783*	*55,092*	*+21%*
Large Connection Contract	-	-	-	0%
Other Regulated Income	4,100	-	4,100	0%
Total Required Revenue	**316,976**	**257,783**	**59,192**	**+23%**

The increase in the return in investment is attributable to the reset of the DPP and the uplift in the weighted average cost of capital from 4.23% to 6.44%. The Commission allowed a step change in required revenues to fund the network growth required to support a decarbonised future. The increase in transmission charges is due to the increase in required revenues that Transpower received from the reset of its individual price path (IPP) decision.

9.2.1 Change in Operations & Maintenance Costs

Our operations and maintenance costs are forecast to increase by +$0.6 million (or +2%) for the 1 April 2025 pricing year when compared against the prior pricing year 1 April 2024. Table 10 provides a comparison of our operations and maintenance costs expenditure, by cost component, between pricing years.

Table 10: Comparison of operations and maintenance costs between pricing years

Description	1 April 2025 ($'000)	1 April 2024 ($'000)	Movement ($'000)	Percent
Service Interruptions and Emergencies	9,856	9,390	466	+5%
Vegetation Management	4,933	4,200	733	+17%
Routine and Corrective Maintenance	16,032	16,778	(746)	-4%
Asset Replacement and Renewal	3,085	2,939	146	+5%
Total Operations and Maintenance Costs	**33,906**	**33,307**	**599**	**+2%**

The movement reflects the significant upward pressure on input costs experienced during the past year, primarily from:

- wages and salaries
- service provider/subcontractor rates
- fuel
- material / components
- traffic management

9.2.2 Change in Administration and Corporate Costs

The Administration and Corporate costs have decreased by ($1.8) million (or -3%). Table 11 compares administration and corporate costs expenditure between pricing years.

Table 11: Comparison of Administration and Corporate Costs between pricing years.

Description	1 April 2025 ($'000)	1 April 2024 ($'000)	Movement ($'000)	Percent
System Operations and Network Support	21,534	22,858	(1,324)	-6%
Business Support	31,038	31,550	(512)	-2%
Total Administration and Corporate Costs	**52,572**	**54,408**	**(1,836)**	**-3%**

The ($0.5) million (or -2%) decrease in business support costs is a response to general budget pressures. The main driver of the ($1.3) million (or -6%) decrease in system operations and network support, is the efficiencies gained from our data and digitalisation project.

9.2.3 Change in Other Costs

The increase in Depreciation Charges of +$2.9 million (or +5%) reflects the increasing value of our electricity network assets, which are subject to annual regulatory revaluation. Table 12 compares depreciation charges between pricing years.

Table 12: Comparison of Depreciation charges between pricing years.

Description	1 April 2025 ($'000)	1 April 2024 ($'000)	Movement ($'000)	Percent
System Fixed Assets	53,914	51,000	2,914	+6%
Non-system Fixed Assets	5,000	5,000	-	0%
Total Depreciation Costs	**58,914**	**56,000**	**2,914**	**+5%**

The increase in transmission costs of +$10.4 million (or +17%) is due to an increase in charges as per Transpower's notification to consumers. Transpower sets its prices per the Transmission Pricing Methodology (TPM) administered by the Authority. More information on the TPM can be found on the Authority's website.[12]

9.3 Recovery of Required Revenue from consumer groups

We recover our required revenue from consumers through prices. Table 13 provides a breakdown of the required revenue we recover through prices by consumer group for the pricing year.

Table 13: Required Revenue by connection grouping for the pricing year

Consumer Group	Required Revenue ($'000)	Proportion of total Required Revenue
Street Lighting	1,565	1%
Residential Low User	107,707	34%
Residential Standard User	71,805	23%
Small General Connections	7,377	2%
Medium General Connections	28,333	9%
Large General Connections	40,763	13%
Residential Two-way Power Flow	2,090	1%
Commercial Two-way Power Flow	144	0%
Irrigation Connections	6,021	2%
Major Customer and Embedded Network Connections	42,138	13%
Large Capacity Connections	4,933	2%
Total Revenue Recovered from Prices	**312,876**	**100%**

As discussed, our pricing approach aims to set efficient and appropriate prices. When setting prices, we do so with the objectives of fairness, sending price signals to consumers, avoiding bill shock, and consistency with the Authority's Pricing Principles. We set prices to recover the total required revenue over the pricing year to meet our aims and objectives.

10. Our Approach to setting prices

To set prices, we use a bottom-up approach that includes two steps.

- Step 1 – allocate the required revenue (cost to serve) by location to each consumer group
- Step 2 — set prices for each consumer group to recover that required revenue through our prices (target revenue).

[12] https://www.ea.govt.nz/operations/transmission/transmission-pricing

10.1 Step 1 –allocate the revenue requirement by location and to consumer group

Using our cost to supply model (CoSM) we allocate the required revenue by location and then to consumer group. Our network is connected to eight grid exit points (GXP's). Several of those GXP's are tied, which means if consumers cannot be supplied by the closet GXP to them they can be supplied through another by switching. We consider GXP to be appropriately granular for the purposes of our CoSM and accordingly we allocate costs to the eight GXP's to which our network connects—

- Arthurs Pass
- Bromley
- Castle Hill
- Coleridge
- Hororata
- Islington
- Kimberley
- Norwood

Then we allocate the costs to our ten consumer groups. We consider consumer group to be sufficiently representative of the consumers on our network. Consumers are assigned to a consumer group based on how they use our network, size of their connection and primary function. Table 14 provides a list of our ten consumer groups.

Table 14: List of our ten consumer groups

Streetlighting
Residential Low User
Residential Standard User
Small General Connection
Medium General Connection
Large General Connection
Residential Two-way Power Flow
Commercial Two-way Power Flow
Irrigation Connections
Major Customers and Embedded networks Connections
Large Customer Connections

10.2 Step 2—set the prices by which we recover our Target Revenue

We set the prices for each consumer group using our pricing design model. The model takes the cost to serve allocated by location and consumer group and derives distribution, pass-through and transmission prices from which we recover our Target Revenue.

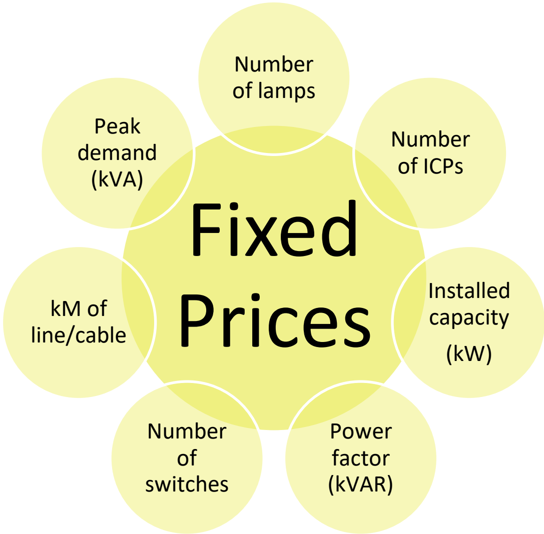
We have two price types:

- fixed based on the type of connection and are static (e.g., kW, kVA, kVAR, meters, etc); and
- volumetric based on consumption and vary depending on when the consumer consumes electricity (kWh).

The mix of fixed charges is shown in Figure 10 and the mix of variable charges is shown in Figure 11.

Figure 10: Mix of fixed prices

Figure 11: Mix of Variable prices



While we calculate distribution, pass-through, and transmission prices and locational prices, we do not bill those. Instead, we roll the distribution, pass-through and transmission prices up to set uniform delivery charges that apply no matter where the consumer is on our network.

10.2.1 Why do we apply a uniform delivery charge

We have elected to continue applying a uniform delivery charge, that is indifferent of location and inclusive of distribution, pass-through, and transmission prices for this pricing year.

Our current billing approach is simple and cost-effective; changing that approach to accommodate non-standard prices would add significant costs to billing, without a traceable benefit to consumers.

The Authority recognised the importance of weighing the cost versus benefits of adopting greater granularity in its Practice Note as follows:

> *'Granularity matters. The prices and regulated charges for electricity services vary significantly at different times and in…'*

We will reconsider applying uniform delivery charges before setting prices each year. When consumers realise the benefits of more granular prices, we will change our approach and take the necessary steps to implement more granulated prices.

10.3 Overview of our approach to allocating the Revenue Requirement

10.3.1 Allocate the Revenue Requirement at the GXP to consumer groups

As discussed in the previous section the CoSM firstly allocates our Revenue Requirement across the eight GXPs that our network connects to, based on the principal drivers of the cost components of the Required Revenue. The eight drivers of cost we use at each GXP are shown in Table 15

Table 15: The allocation to each GXP by cost driver

GXP	Arthurs Pass	Bromley	Castle Hill	Coleridge	Hororata	Islington	Kimberley	Norwood
No of ICP	0.1%	25.6%	0.1%	0.1%	2.0%	69.7%	0.4%	2.1%
Installed Capacity (kW)	0.1%	22.3%	0.1%	0.1%	3.5%	71.0%	0.5%	2.5%
Asset Utilisation	0.1%	22.3%	0.1%	0.1%	3.5%	71.0%	0.5%	2.5%
Consumption (kWh)	0.0%	18.8%	0.0%	0.1%	2.2%	72.7%	1.1%	5.1%
Line Length (meters)	0.1%	19.3%	0.2%	0.1%	2.7%	66.0%	0.7%	11.0%
RAB ($)	0.1%	22.3%	0.1%	0.1%	3.5%	71.0%	0.5%	2.5%
RAB Depreciation ($)	0.1%	22.3%	0.1%	0.1%	3.5%	71.0%	0.5%	2.5%

1 April 2025 is the second year we are using this approach. Before 1 April 2024, costs were allocated to consumer groups based on ∑ AMD, after diversified maximum demand (ADMD) and average regulatory value (RIV). Last pricing year, we moved to a more granular approach apportioning costs in support of cost reflective pricing. The five cost drivers above were chosen as we have readily available information for these drivers. Making the approach straightforward, appropriate, and fair.

10.3.2 Allocate the Revenue Requirement at the GXP to consumer groups

Using the allocated Required Revenue by GXP, the CoSM next allocates the Revenue Requirement by GXP to the consumer groups, again based on the driver of the cost to serve each consumer group. Table 34 to Table 41, at Appendix F, show the five drivers that we use to allocate costs to the consumer groups, and the allocation of costs to each GXP.

10.3.3 Historical quantities to allocate the Required Revenue

We use historical quantities to allocate the required revenue to each consumer group by the GXP. The historical quantities used to allocate the Required Revenue for the pricing year is shown at Table 16. Table 42 to Table 49, at Appendix G, show the historical quantities that we have used to allocate the required revenue for each consumer group at each GXP

Table 16: Quantities used to allocate the Required Revenue for the pricing year

Consumer Group	ICPs / Supplies (Number)	Consumption (kWh)	Installed capacity (kVA)	Asset utilisation (kW)	Line length (meters)	RAB ($'000)	RAB Depreciation ($'000)
Streetlighting	30	41,324,275	3,926	2,748	8,386		
Residential Low User	117,331	925,625,464	1,821,924	1,275,347	4,291,827		
Residential Standard User	78,221	617,083,642	1,214,616	850,231	2,861,218		
Small General Connection	9,370	78,563,399	110,486	77,340	305,191		
Medium General Connection	11,472	245,512,650	468,622	328,036	1,258,515		
Large General Connections	4,167	299,384,156	731,419	511,994	1,780,194		
Residential Two-way Power Flow	1,900	14,989,094	36,967	25,877	92,540		
Commercial Two-way Power Flow	100	2,492,943	1,374	962	3,526		
Irrigation Connections	1,050	46,124,329	101,006	70,704	612,478		
Major Customer Connections	322	843,976,253	316,605	221,624	778,124		
Total	**223,963**	**3,115,076,205**	**4,806,946**	**3,364,862**	**11,992,000**		
Network	Sub transmission Lines					81,007,000	2,936,000
	Sub transmission Cables					104,129,000	3,110,000
	Zone Substation					178,917,000	8,530,000
	Distribution LV Lines					155,607,000	6,143,000
	Distribution LV cables					468,494,000	15,669,000
	Distribution substations and transformers					166,524,000	4,771,000
	Distribution switchgear					191,658,000	7,397,000
	Other network assets					42,494,000	2,005,000
Non-Network	Non-Network assets					61,249,000	4,987,000
Total						**1,450,079,000**	**55,548,000**

10.4 Overview of our approach to setting Target Revenue

The pricing design model sets out how we recover our Target Revenue for each consumer group over the pricing year. The pricing design model first sets distribution and transmission prices for each consumer group by GXP and then a uniformed delivery charge.

10.4.1 Determine the fixed / variable split

Historically we have set delivery charges with a low fixed and high variable component as we have applied a consumption-based approach to pricing. As we transition our prices to become use-based, we will increase the fixed component and decrease the variable to improve cost reflectivity while retaining a level of variable price signalling. Table 17 compares the fixed and variable split applied in this pricing year to the prior pricing year.

Table 17: Comparison of the fixed / variable split between pricing years

Consumer Group		1 April 2025		1 April 2024	
		Fixed	Variable	Fixed	Variable
Streetlighting	LIG	100%	-	28%	72%
Residential Low User	LOW	25%	75%	25%	75%
Residential Standard User	RSU	41%	59%	NA	NA
Small General Connection	GEN(GC1)	59%	41%	36%	64%
Medium General Connection	GEN(GC2)	51%	49%	18%	82%
Large General Connections	GEN(GC3)	62%	38%	24%	76%
Residential Two-way Power Flow	2WAYRES	21%	79%	NA	NA
Commercial Two-way Power Flow	2WAYSME	37%	63%	NA	NA
Irrigation Connections	IRR	69%	31%	19%	81%
Major Customer and Embedded Network Connections	MCC	100%	-	100%	-
Large Capacity Connections	LCC	100%	-	100%	-

10.4.2 Calculate and set the fixed and variable charges

We set the fixed and variable charges within each consumer group by using the following formula

((CoSM allocated Required Revenue x split) x allocation to price / quantities)

Each connection group has one fixed charge:

- Residential and SME connection have a per-day ICP charge
- Irrigation connections have a per day, per chargeable capacity kVA charge
- Major customers have a per day, per chargeable capacity kVA charge
- Street Lighting connections have a per lamp per day charge

Table 18 shows the proportion of the Target Revenue recovered through fixed charges for each consumer group.

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Table 18: Breakdown of Target Revenue recovered through fixed and variable revenue.

Consumer Group		Fixed Revenue ($'000)	Variable Revenue ($'000)	Target Revenue ($'000)
Streetlighting	LIG	1,565	-	1,565
Residential Low User	LOW	27,305	81,402	108,707
Residential Standard User	RSU	30,025	43,284	73,310
Small General Connection	GEN(GC1)	6,245	4,391	10,636
Medium General Connection	GEN(GC2)	11,644	11,250	22,894
Large General Connections	GEN(GC3)	18,615	11,349	29,964
Residential Two-way Power Flow	2WAYRES	520	2,001	2,521
Commercial Two-way Power Flow	2WAYSME	53	91	144
Irrigation Connections	IRR	8,065	3,662	11,727
Major Customer and Embedded Network Connections	MCC	46,474	-	46,474
Large Capacity Connections	LCC	4,933	-	4,933
	Total	**155,445**	**157,430**	**312,876**

Each connection category (excluding Major and LCC connections) have five variable prices - weekend, peak, shoulder, off-peak, super off-peak units per kWh as shown in Table 19. Accordingly, the costs are allocated to variable charges across each consumer group's variable price components.

Table 19: Allocation of variable prices (i.e. TOU) for the pricing year

Consumer Group		Weekend	Peak	Shoulder	Off Peak	Super off peak
Streetlighting	LIG	-	-	-	-	-
Residential Low User	LOW	26%	32%	24%	13%	5%
Residential Standard User	RSU	26%	32%	24%	13%	5%
Small General Connection	GEN(GC1)	26%	32%	24%	13%	5%
Medium General Connection	GEN(GC2)	26%	32%	24%	13%	5%
Large General Connections	GEN(GC3)	26%	32%	24%	13%	5%
Residential Two-way Power Flow	2WAYRES	25%	37%	22%	11%	5%
Commercial Two-way Power Flow	2WAYSME	25%	37%	22%	11%	5%
Irrigation Connections	IRR	25%	27%	24%	15%	8%
Major Customer and Embedded Network Connections	MCC	-	-	-	-	-
Large Capacity Connections	LCC	-	-	-	-	-

10.4.3 We smooth prices to avoid bill shock

We use the allocation to variable prices to smooth end prices so we can:

- meet our regulatory requirements (e.g., transition arrangements of low fixed charge regulations) by capping fixed daily charges for residential consumers to recover our Required Revenue
- avoid bill shock to consumers as we evolve our prices to be more cost reflective.

We use a three-step process to smooth variable prices

Step 1 — Set the initial allocations based on the future pricing strategy.

Step 2 — Adjust prices to comply with the transition arrangement of low fixed charge regulations.

Step 3 — Spread the under-recovered revenue from applying step 2 across the SME consumers in a fair manner that avoids bill shock to the consumers in those consumer groups.

10.4.4 We use forecast year-end quantities to set prices

We use year-end forecast quantities when setting our prices. Quantities are forecast for each consumer group based on the prior year's quantities multiplied by a growth factor. We use a combination of quantities to set prices:

- No of ICPs / Lamps
- Installed capacity (kVA)
- Demand (kVA)
- Consumption weekend (kWh)
- Consumption Peak (kWh)
- Consumption Shoulder (kWh)
- Consumption Off-Peak (kWh)
- Consumption Super off-peak (kWh)

Table 20 shows the forecast quantities we used for each consumer group to set this year's prices.

Table 20: Forecast quantities for this pricing year

	Streetlighting *LIG*	Residential Low User *LOW*	Residential Standard user *RSU*	Small General Connection *GEN(GC1)*	Medium General Connection *GEN(GC2)*	Large General Connection *GEN(GC3)*	Residential Two-way Power Flow *2WAYRES*	Commercial Two-way Power Flow *2WAYSME*	Irrigation Connections *IRR*	Major Customer Connections *MCC*
Number of ICPs/ lamps	54,332	118,133	78,755	11,444	11,832	4,263	1,900	100	1,050	322
Consumption Weekend (kWh)	-	254,199,846	169,466,564	20,964,054	64,463,689	78,702,534	5,863,922	308,627	35,721,302	-
Consumption Peak (kWh)	-	315,218,847	210,145,898	25,996,337	79,937,774	97,594,560	7,271,518	382,711	38,169,209	-
Consumption Shoulder (kWh)	-	234,126,164	156,084,109	19,308,562	59,373,114	72,487,543	5,400,859	284,256	33,636,440	-
Consumption Off Peak (kWh)	-	130,138,121	86,758,747	10,732,589	33,002,315	40,291,920	3,002,047	158,002	21,459,876	-
Consumption Super Off Peak (kWh)	-	54,120,279	36,080,186	4,463,340	13,724,606	16,756,120	1,248,455	65,708	11,268,018	-
Installed capacity (kVA)	-	-	-	-	-	-	-	-	76,484	389,193
Demand (kVA)	-	-	-	-	-	-	-	-	-	310,052

10.4.5 Target Revenue is derived by multiplying prices by forecast quantities

The target revenue for each consumer group is set by using the following formula –

Price x Forecast quantities = Target Revenue

Table 21 provides a breakdown of the Target Revenue for each consumer group and the proportion of total revenue that consumer group equates to.

Table 21: Allocation and proportion of the Target Revenue between connection groups

Consumer Group		Target Revenue ($'000)	Proportion of Total Target Revenue
Streetlighting	LIG	1,565	1%
Residential Low User	LOW	107,707	34%
Residential Standard User	RSU	71,805	23%
Small General Connection	GEN(GC1)	7,377	2%
Medium General Connection	GEN(GC2)	28,333	9%
Large General Connections	GEN(GC3)	40,763	13%
Residential Two-way Power Flow	2WAYRES	2,090	1%
Commercial Two-way Power Flow	2WAYSME	144	0%
Irrigation Connections	IRR	6,021	2%
Major Customer and Embedded Network Connections	MCC	42,138	13%
Large Capacity Connections	LCC	4,933	2%
	Total	**312,876**	**100%**

10.5 Change in Target Revenue

Target Revenue has increased by $55.2 million (or+21%) for this pricing year. Table 22 shows the movement in Target Revenue by consumer group between pricing years.

Table 22: Movement in Target Revenue within connection groups between pricing years

Consumer Group		1 April 2025 ($'000)	1 April 2024 ($'000)	Movement ($'000)	Percent
Streetlighting	LIG	1,565	909	656	+72%
Residential Low User	LOW	107,707	147,503	(39,796)	-27%
Residential Standard User	RSU	71,805	-	71,805	+100%
Small General Connection	GEN(GC1)	7,377	9,764	(2,388)	-24%
Medium General Connection	GEN(GC2)	28,333	22,845	5,488	+24%
Large General Connections	GEN(GC3)	40,763	24,641	16,122	+65%
Residential Two-way Power Flow	2WAYRES	2,090	-	2,090	+100%
Commercial Two-way Power Flow	2WAYSME	144	-	144	+100%
Irrigation Connections	IRR	6,021	10,033	(4,012)	-40%
Major Customer and Embedded Network Connections	MCC	42,138	38,121	4,017	+11%
Large Capacity Connections	LCC	4,933	3,882	1,051	+27%
	Total	**312,876**	**257,700**	**55,176**	+21%

11. Loss Factors

Losses are the percentage of electricity entering the network lost during the delivery to consumer's connections (i.e., ICPs). The quantity of electricity metered at ICPs is net of losses. The consumption proportion assigned to each retailer at the GXP is determined by the electricity measured at the consumer's meter multiplied by a loss factor.

There are two components to loss factors on our network:

- Fixed component due to the standing losses of the distribution transformers; and
- Variable component arising from the heating effect of resistance on the lines.

In 2023, we undertook a review of loss factors using the methodology outlined in the Electricity Authority's guideline. The revised and updated loss factors for the pricing year are provided in Table 23. The new loss factors will be effective 1 April 2025.

Table 23: Loss factors for the pricing year

Code	Loss Factor	Description
LVL	1.0452	Low voltage metered connections (230v or 400v)
11L	1.0229	11kV metered connections
SLL	1.0068	Connection specific factors (HV)
FSL	1.0068	Connection specific factors (HV)

12. Distributed Generation

Interest in utility-scale solar connections has significantly increased since 2022. Inquiries indicate potential for 400MW of solar PV/wind generation to be added within Region B. We have 185 small photovoltaic installations under 10kW.

Summer peaks sometimes occur after 7pm when solar radiation is reduced. Together with cloud cover the solar generation can be less than 5% of nameplate capacity at the time of peak load. We plan to monitor the output of these solar connections so their contribution can be excluded from our peaks which will reveal the change in underlying load. Standard forecasting methodology can be applied to this underlying load, with the solar output reported separately.

Currently, no distributed generation feeds in at high voltage onto our network.

12.1 Solar 10kW or less

Systems of this size are typically installed in homes and small businesses whereas systems greater than 10 kilowatts are typically used by larger businesses.

Distributed generation must meet all relevant statutory and regulatory requirements and comply with all applicable safety standards. As there is no incremental cost associated with the connection of small distribution generation load, we currently charge a nominal application fee.

12.2 Business 10kW or more

Distributed generators, also known as 'embedded generators', are located at a home or business to produce electricity for that home or business's own use. They may also be capable of putting surplus energy back into our distribution network. These generators can take several forms: solar panels, wind or micro-hydro turbines and diesel generators are the most common. These systems are usually three-phase, and are typically installed at industrial, commercial or rural sites.

Our policies relating to the connection of distributed generation can be found on our website at Solar or diesel generation | The Orion Group.

13. Capital contributions

Capital contribution applies generally to the up-front cost a consumer will pay when connecting to the network. Primarily, we look to apply economic consideration to the balance between socialisation (shallow charging) and causer pays (deep charging) when setting our approach to connection charges.

Our approach to charges for connections and extensions forms part of our broader efficient pricing policies and our economic approach to recovery of costs for providing our delivery service. With this approach, consumers (particularly prospective consumers) make efficient decisions about which form of energy to use, and where to locate new load. We endeavour to provide new connections and enhanced capacity wherever it is economically viable, and our Connections and Extensions Methodology[13] sets out our approach to establish this economic viability. However, there may be situations where it is imprudent, environmentally unsound or physically impracticable to provide supply or enhanced capacity.

Ideally, each new connection would pay for any necessary extension and reinforcement through its future delivery charges. However, several factors prevent this balance from occurring:

- we must apply price averaging over large groups of connections, because it is not practical to single out individual connections for cost-specific delivery pricing
- the life and future utilisation of new connections are not known, so the present value of future delivery charges cannot be calculated with certainty
- the assets involved have very long lives and it is not viable to lock some consumers into a contract over a matching period
- network reinforcement is incremental, it is often more efficient for us to add large amounts of capacity at a time (unlocking economies of scale)
- dedicated assets often become shared assets as the network expands. Existing consumers should share in the benefit of greater utilisation of shared assets (and other

14. Export Credits have been grandfathered

As discussed at section 5, this year we have introduced the Two-way power flow consumer groups for our general pricing categories[14]. From 1 April 2025 consumers who elect to be in a Two-way power flow consumer groups receive consideration for their export at peak times via an injection credit that off-sets their consumption at their connection. In making the decision to introduce the new consumer

[13] Pricing guides and information | The Orion Group

[14] Our general pricing categories include residential, small, medium and large general connections.

groups we also decided that our will no longer give export credits under our existing policy to residential and commercial consumers.

We have retained the credits for exports for irrigation connections, major customers, and large customer connections. These consumers are not eligible for the Residential Two-way Power Flow or Commercial Two-way Power Flow consumer groups; accordingly, we believe it appropriate that the export credits under our existing policy continue to apply to these consumers until such time as we derive an alternative form of consideration.

14.1 What has been our export credit policy?

Distributed generation that reliably generates during peak demand times can provide an economical alternative to electricity delivery and we provide export credits in recognition of this benefit to the network. Our export credits do not represent the purchase of electricity, and consumers are able to separately negotiate to sell exported energy with other parties, usually with their electricity retailer.

Payments to generators are a cost incurred in providing our delivery service and, as with all other delivery costs, must be recovered from the consumers that use our network.

We do not specifically charge consumers for exporting electricity to our network; however, consumers would be expected to fund any costs associated with situations where our network needed to be upgraded to accommodate the exported electricity. Separately, the nominated maximum demand charge for major customers, which broadly reflects the sizing of network delivery assets near the consumer, is based on export demands where this is more than double the load demands, so excess peak export can increase delivery charges.

14.2 How are export credit prices calculated?

Export credits are based on the amount of electricity injected into our network during peak loading periods. The cost of delivery during peak loading is represented by our assessment of LRAIC which we calculate as $102 per kW[15] per year. The approach that we take to derive the LRAIC is shown in Table 24.

Some of the costs represented in this LRAIC are not alleviated via export for example, the required size for distribution transformers and low voltage systems is usually unchanged when generation is installed. Further, some network areas experience peaks that are not aligned with the timing of our signalled peak periods, and we reduce the standard credit price to reflect this divergence as well. Combining these factors, the distribution credit price is set at approximately a third of the full LRAIC.

We then separate the credit between real (kW) and reactive (kVAr) components of export, and we cap the amount of reactive export that is eligible for credits, to encourage appropriate levels of each.

Different categories are maintained to generally reflect the different metering information available from different sites, and standard credits are capped at 750kW of generation – above this level we individually consider the benefits to the network and apply specific pricing. We set a lower credit price for export that includes PV and where the metering arrangement only records total monthly export (referred to as “non-half-hour metering”) rather than the actual time that energy was exported. The

[15] Assumes a power factor of 1.

lower price reflects average coincidence between export from PV generation and our network peak demands (usually occurring on cold winter days and evenings) that we observe at connections that do have the necessary metering for this assessment.

Table 24: Our approach to LRAIC

Step 1	Establish expected peak demand during the year	Upper HV network	680.2 MVA
		Lower LV network	554.8 MVA
Step 2	Estimate the replacement cost of the network	Upper HV network	$1,557 m
		Lower LV network	$639 m
		Total replacement cost	$2,195 m
Step 3	Estimate the proportion of replacement cost that is load dependent	Upper HV network	$911 m
		Lower LV network	$298 m
		Total replacement cost	$1,209 m
Step 4	Estimate the proportion of the load dependent replacement cost that is sized for loadings coincident with network peaks	Upper HV network	$763 m
		Lower LV network	$88 m
		Total replacement cost	$851 m
Step 5	Calculate load dependent replacement cost per kVA	Upper HV network	$1,121 /kVA
		Lower LV network	$159 / kVA
		Total replacement cost	$1,280 / KVA
Step 6	Annualise the replacement costs and add in network average operations and maintenance	Upper HV network	$91.35 /kVA/year
		Lower LV network	$10.60 / kVA/year
		Total	**$101.95 / kVA/year**

Exporting generators also reduce our exposure to Transpower's charges if they generate during Transpower's peak demand periods. The Electricity Authority has revised the rules so that we are only able to reflect this savings in the credits applied to customers for generating connections that they approve, and at the date of this publication, no connections have been approved by the Electricity Authority.

Orion

Appendix A - Price schedules

Electricity delivery price schedule for Orion NZ Ltd							
(applicable from 1 April 2025)							
This schedule lists the prices that Orion uses to charge electricity retailers and directly contracted customers for the electricity delivery service in Orion's network area. This delivery service includes the transmission and distribution of electricity to homes and businesses but does not include the cost of electricity itself. Please refer to your retailer for details of retail electricity prices.							
All prices exclude GST	**Price Category Code [2]**	**Price Component Code [2]**	**Distribution Price**	**Pass-through & Recoverable Price**	**Transmission Price**	**Delivery Price**	**Unit of measure**
Streetlighting	LIG						
Fixed charge		LIGFXD	$ 0.0660	$ 0.0101	$ 0.0027	$ 0.0789	$/lamp/day
Variable Charges							
Weekends		LIGWKD	$ -	$ -	$ -	$ -	$/kWh
Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm)		LIGP	$ -	$ -	$ -	$ -	$/kWh
Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm)		LIGSH	$ -	$ -	$ -	$ -	$/kWh
Off Peak (Mon to Fri, 10:00pm to 3:00am)		LIGOP	$ -	$ -	$ -	$ -	$/kWh
Super Off Peak (Anytime between 3:00am to 5:00am)		LIGSOP	$ -	$ -	$ -	$ -	$/kWh

Residential Low User							
Uncontrolled Charges	URES						
Residential Connection - Fixed Daily Charge - Uncontrolled		URESUFXD	$ 0.4778	$ 0.0459	$ 0.2263	$ 0.7500	$/con/day
Weekends - Uncontrolled		URESUWKD	$ 0.03037	$ 0.00122	$ 0.00754	$ 0.03913	$/kWh
Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm) - Uncontrolled		URESUP	$ 0.12116	$ 0.00486	$ 0.03009	$ 0.15611	$/kWh
Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm) - Uncontrolled		URESUSH	$ 0.07000	$ 0.00280	$ 0.01821	$ 0.09101	$/kWh
Off Peak (Mon to Fri, 10:00pm to 3:00am) - Uncontrolled		URESUOP	$ 0.00558	$ 0.00023	$ 0.00140	$ 0.00721	$/kWh
Super Off Peak (Anytime between 3:00am to 5:00am) - Uncontrolled		URESUSOP	$ -	$ -	$ -	$ -	$/kWh
Controlled Charges	RES						
Residential Connection - Fixed Daily Charge - Controlled		RESCFXD	$ 0.3352	$ 0.0459	$ 0.2268	$ 0.6078	$/con/day
Weekends - Controlled		RESCWKD	$ 0.03037	$ 0.00122	$ 0.00754	$ 0.03913	$/kWh
Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm) - Controlled		RESCP	$ 0.12116	$ 0.00486	$ 0.03009	$ 0.15611	$/kWh
Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm) - Controlled		RESCSH	$ 0.07000	$ 0.00280	$ 0.01821	$ 0.09101	$/kWh
Off Peak (Mon to Fri, 10:00pm to 3:00am) - Controlled		RESCOP	$ 0.00558	$ 0.00023	$ 0.00140	$ 0.00721	$/kWh

Super Off Peak (Anytime between 3:00am to 5:00am) - Controlled		RESCSOP	$ -	$ -	$ -	$ -	$/kWh
Residential Standard User							
Uncontrolled Charges	RSU						
Residential Connection - Fixed Daily Charge - Uncontrolled		RSUUFXD	$ 0.8881	$ 0.0460	$ 0.2272	$ 1.1613	$/con/day
Weekends - Uncontrolled		RSUUWKD	$ 0.02233	$ 0.00122	$ 0.00754	$ 0.03109	$/kWh
Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm) - Uncontrolled		RSUUP	$ 0.08962	$ 0.00486	$ 0.03009	$ 0.12458	$/kWh
Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm) - Uncontrolled		RSUUSH	$ 0.05159	$ 0.00280	$ 0.01821	$ 0.07260	$/kWh
Off Peak (Mon to Fri, 10:00pm to 3:00am) - Uncontrolled		RSUUOP	$ 0.00420	$ 0.00023	$ 0.00140	$ 0.00582	$/kWh
Super Off Peak (Anytime between 3:00am to 5:00am) - Uncontrolled		RSUUSOP	$ -	$ -	$ -	$ -	$/kWh
Controlled Charges	RSC						
Residential Connection - Fixed Daily Charge - Controlled		RSCCFXD	$ 0.7466	$ 0.0459	$ 0.2266	$ 1.0191	$/con/day
Weekends - Controlled		RSCCWKD	$ 0.02233	$ 0.00122	$ 0.00754	$ 0.03109	$/kWh
Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm) - Controlled		RSCCP	$ 0.08962	$ 0.00486	$ 0.03009	$ 0.12458	$/kWh
Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm) - Controlled		RSCCSH	$ 0.05159	$ 0.00280	$ 0.01821	$ 0.07260	$/kWh

Off Peak (Mon to Fri, 10:00pm to 3:00am) - Controlled		RSCCOP	$ 0.00420	$ 0.00023	$ 0.00140	$ 0.00582	$/kWh
Super Off Peak (Anytime between 3:00am to 5:00am) - Controlled		RSCCSOP	$ -	$ -	$ -	$ -	$/kWh
Small General Connection							
Uncontrolled Charges	UGENGC1						
Small Connection up to 15 kVA - Fixed Daily Charge - Uncontrolled		UGENGC1UFXD	$ 1.1295	$ 0.0760	$ 0.3283	$ 1.5338	$/con/day
Weekends - Uncontrolled		UGENGC1UWKD	$ 0.02312	$ 0.00049	$ 0.00189	$ 0.02550	$/kWh
Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm) - Uncontrolled		UGENGC1UP	$ 0.09269	$ 0.00195	$ 0.00752	$ 0.10216	$/kWh
Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm) - Uncontrolled		UGENGC1USH	$ 0.05385	$ 0.00112	$ 0.00455	$ 0.05953	$/kWh
Off Peak (Mon to Fri, 10:00pm to 3:00am) - Uncontrolled		UGENGC1UOP	$ 0.00433	$ 0.00009	$ 0.00035	$ 0.00477	$/kWh
Super Off Peak (Anytime between 3:00am to 5:00am) - Uncontrolled		UGENGC1USOP	$ -	$ -	$ -	$ -	$/kWh
Controlled Charges	GENGC1						
Small Connection up to 15 kVA - Fixed Daily Charge - Controlled		GENGC1CFXD	$ 1.0736	$ 0.0605	$ 0.2625	$ 1.3967	$/con/day
Weekends - Controlled		GENGC1CWKD	$ 0.02312	$ 0.00049	$ 0.00189	$ 0.02550	$/kWh
Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm) - Controlled		GENGC1CP	$ 0.09269	$ 0.00195	$ 0.00752	$ 0.10216	$/kWh

Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm) - Controlled		GENGC1CSH	$ 0.05385	$ 0.00112	$ 0.00455	$ 0.05953	$/kWh
Off Peak (Mon to Fri, 10:00pm to 3:00am) - Controlled		GENGC1COP	$ 0.00433	$ 0.00009	$ 0.00035	$ 0.00477	$/kWh
Super Off Peak (Anytime between 3:00am to 5:00am) - Controlled		GENGC1CSOP	$ -	$ -	$ -	$ -	$/kWh
Medium General Connection							
Uncontrolled Charges	UGENGC2						
Medium Connection 16 kVA up to 69 kVA - Fixed Daily Charge - Uncontrolled		UGENGC2UFXD	$ 2.2385	$ 0.0469	$ 0.4351	$ 2.7204	$/con/day
Weekends - Uncontrolled		UGENGC2UWKD	$ 0.00992	$ 0.00190	$ 0.00943	$ 0.02124	$/kWh
Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm) - Uncontrolled		UGENGC2UP	$ 0.03991	$ 0.00759	$ 0.03761	$ 0.08511	$/kWh
Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm) - Uncontrolled		UGENGC2USH	$ 0.02248	$ 0.00437	$ 0.02276	$ 0.04961	$/kWh
Off Peak (Mon to Fri, 10:00pm to 3:00am) - Uncontrolled		UGENGC2UOP	$ 0.00188	$ 0.00035	$ 0.00175	$ 0.00398	$/kWh
Super Off Peak (Anytime between 3:00am to 5:00am) - Uncontrolled		UGENGC2USOP	$ -	$ -	$ -	$ -	$/kWh
Controlled Charges	GENGC2						
Medium Connection 16 kVA up to 69 kVA - Fixed Daily Charge - Controlled		GENGC2CFXD	$ 2.1991	$ 0.0376	$ 0.3473	$ 2.5840	$/con/day
Weekends - Controlled		GENGC2CWKD	$ 0.00992	$ 0.00190	$ 0.00943	$ 0.02124	$/kWh

Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm) - Controlled		GENGC2CP	$ 0.03991	$ 0.00759	$ 0.03761	$ 0.08511	$/kWh
Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm) - Controlled		GENGC2CSH	$ 0.02248	$ 0.00437	$ 0.02276	$ 0.04961	$/kWh
Off Peak (Mon to Fri, 10:00pm to 3:00am) - Controlled		GENGC2COP	$ 0.00188	$ 0.00035	$ 0.00175	$ 0.00398	$/kWh
Super Off Peak (Anytime between 3:00am to 5:00am) - Controlled		GENGC2CSOP	$ -	$ -	$ -	$ -	$/kWh
Large General Connections							
Uncontrolled Charges	UGENGC3						
Large Connection >70 kVA - Fixed Daily Charge - Uncontrolled		UGENGC3UFXD	$ 8.5546	$ 0.5363	$ 2.8916	$ 11.9824	$/con/day
Weekends - Uncontrolled		UGENGC3UWKD	$ 0.00750	$ 0.00101	$ 0.00905	$ 0.01755	$/kWh
Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm) - Uncontrolled		UGENGC3UP	$ 0.03021	$ 0.00401	$ 0.03611	$ 0.07033	$/kWh
Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm) - Uncontrolled		UGENGC3USH	$ 0.01683	$ 0.00231	$ 0.02185	$ 0.04099	$/kWh
Off Peak (Mon to Fri, 10:00pm to 3:00am) - Uncontrolled		UGENGC3UOP	$ 0.00142	$ 0.00019	$ 0.00168	$ 0.00329	$/kWh
Super Off Peak (Anytime between 3:00am to 5:00am) - Uncontrolled		UGENGC3USOP	$ -	$ -	$ -	$ -	$/kWh
Controlled Charges	GENGC3						
Large Connection >70 kVA - Fixed Daily Charge - Controlled		GENGC3CFXD	$ 9.0906	$ 0.4278	$ 2.3198	$ 11.8382	$/con/day

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Weekends - Controlled		GENGC3CWKD	$ 0.00750	$ 0.00101	$ 0.00905	$ 0.01755	$/kWh
Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm) - Controlled		GENGC3CP	$ 0.03021	$ 0.00401	$ 0.03611	$ 0.07033	$/kWh
Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm) - Controlled		GENGC3CSH	$ 0.01683	$ 0.00231	$ 0.02185	$ 0.04099	$/kWh
Off Peak (Mon to Fri, 10:00pm to 3:00am) - Controlled		GENGC3COP	$ 0.00142	$ 0.00019	$ 0.00168	$ 0.00329	$/kWh
Super Off Peak (Anytime between 3:00am to 5:00am) - Controlled		GENGC3CSOP	$ -	$ -	$ -	$ -	$/kWh
Residential Two-way Power Flow	2WAYRES						
Residential Connection Fixed Daily Charge		2WAYRESFXD	$ (0.1600)	$ 0.1045	$ 0.8056	$ 0.7500	$/con/day
Residential Consumption Weekends		2WAYRESXWKD	$ 0.03908	$ -	$ -	$ 0.03908	$/kWh
Residential Consumption Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm)		2WAYRESXP	$ 0.21883	$ -	$ -	$ 0.21883	$/kWh
Residential Consumption Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm)		2WAYRESXSH	$ 0.09998	$ -	$ -	$ 0.09998	$/kWh
Residential Consumption Off Peak (Mon to Fri, 10:00pm to 3:00am)		2WAYRESXOP	$ 0.00360	$ -	$ -	$ 0.00360	$/kWh
Residential Consumption Super Off Peak (Anytime between 3:00am to 5:00am)		2WAYRESXSOP	$ -	$ -	$ -	$ -	$/kWh
Residential Injection Weekends		2WAYRESIWKD	$ -	$ -	$ -	$ -	$/kWh
Residential Injection Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm)		2WAYRESIP	$ (0.14548)	$ -	$ -	$ (0.14548)	$/kWh

Residential Injection Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm)		2WAYRESISH	$ -	$ -	$ -	$ -	$/kWh
Residential Injection Off Peak (Mon to Fri, 10:00pm to 3:00am)		2WAYRESIOP	$ -	$ -	$ -	$ -	$/kWh
Residential Injection Super Off Peak (Anytime between 3:00am to 5:00am)		2WAYRESISOP	$ -	$ -	$ -	$ -	$/kWh
Commercial Two-way Power Flow	2WAYSME						
Commercial Connection Fixed Daily Charge		2WAYSMEFXD	$ 0.5283	$ 0.3302	$ 0.5868	$ 1.4453	$/con/day
Commercial Consumption Weekends		2WAYSMEXWKD	$ 0.02520	$ -	$ -	$ 0.02520	$/kWh
Commercial Consumption Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm)		2WAYSMEXP	$ 0.19643	$ -	$ -	$ 0.19643	$/kWh
Commercial Consumption Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm)		2WAYSMEXSH	$ 0.06471	$ -	$ -	$ 0.06471	$/kWh
Commercial Consumption Off Peak (Mon to Fri, 10:00pm to 3:00am)		2WAYSMEXOP	$ 0.00236	$ -	$ -	$ 0.00236	$/kWh
Commercial Consumption Super Off Peak (Anytime between 3:00am to 5:00am)		2WAYSMEXSOP	$ -	$ -	$ -	$ -	$/kWh
Commercial Injection Weekends		2WAYSMEIWKD	$ -	$ -	$ -	$ -	$/kWh
Commercial Injection Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm)		2WAYSMEIP	$ (0.08036)	$ -	$ -	$ (0.08036)	$/kWh
Commercial Injection Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm)		2WAYSMEISH	$ -	$ -	$ -	$ -	$/kWh
Commercial Injection Off Peak (Mon to Fri, 10:00pm to 3:00am)		2WAYSMEIOP	$ -	$ -	$ -	$ -	$/kWh

Commercial Injection Super Off Peak (Anytime between 3:00am to 5:00am)		2WAYSMEISOP	$ -	$ -	$ -	$ -	$/kWh
Irrigation Connections	IRR						
Capacity Charge		IRRCAP	$ 0.5036	$ 0.0139	$ 0.1221	$ 0.6397	$/kW/day*
Power factor correction rebate		IRRPFC	$ (0.13588)	$ -	$ -	$ (0.13588)	$/kVAr/day*
Interruptibility rebate		IRRIRR	$ (0.03365)	$ -	$ -	$ (0.03365)	$/kW/day*
Weekends		IRRWKD	$ 0.01350	$ -	$ -	$ 0.01350	$/kWh
Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm)		IRRP	$ 0.05410	$ -	$ -	$ 0.05410	$/kWh
Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm)		IRRSH	$ 0.03152	$ -	$ -	$ 0.03152	$/kWh
Off Peak (Mon to Fri, 10:00pm to 3:00am)		IRROP	$ 0.00253	$ -	$ -	$ 0.00253	$/kWh
Super Off Peak (Anytime between 3:00am to 5:00am)		IRRSOP	$ -	$ -	$ -	$ -	$/kWh
* applied to 1 October to 31 March only							
Major Customer and Embedded Network Connections	MCC						
Fixed charge		MCFXD	$ 23.8045	$ -	$ -	$ 23.8045	$/con/day
Fixed charge (additional connections)		MCFXDA	$ 17.85336	$ -	$ -	$ 17.85336	$/con/day
Extra switches		EQESW	$ 4.64187	$ -	$ -	$ 4.64187	$/switch/day

11kV Metering equipment		EQMET	$ 6.30819	$ -	$ -	$ 6.30819	$/con/day
11kV Underground cabling		EQUGC	$ 5.59405	$ -	$ -	$ 5.59405	$/km/day
11kV Overhead lines		EQOHL	$ 4.16578	$ -	$ -	$ 4.16578	$/km/day
Transformer capacity		EQTFC	$ 0.01403	$ -	$ -	$ 0.01403	$/kVA/day
Peak charge (control period demand)		MCCPD	$ 0.25427	$ 0.05580	$ 0.05636	$ 0.36643	$/kVA/day
Nominated maximum demand		MCNMD	$ 0.11589	$ 0.00111	$ 0.00112	$ 0.11813	$/kVA/day
Metered maximum demand		MCMMD	$ 0.07552	$ 0.01779	$ 0.01797	$ 0.11128	$/kVA/day
Large Capacity Connections							
Individually assessed prices advised and charged directly to the customers							
Notes							
1. Full details on how we apply these prices are included in our Pricing Policy document, available on our website.							
2. The applicable price category is recorded against each connection ICP on the Electricity Authority's registry, and the price component is used in our mandatory 'electricity information exchange protocol' files.							
3. Weekend means all trading periods except for Super Off Peak between 3am -5am.							
4. Where an ICP has a 'non-communicating' meter for a period of greater than 40 working days all consumption (kWh) will by default be assigned as per the pricing policy.							

		Units	1 April 2024 to 31 March 2025	from 1 April 2025
Connection categories and price components			**Delivery price**	**Delivery price**
			(excl GST)	(excl GST)
Streetlighting connections (approx 54,332 lamps)				
	Fixed charge	$/lamp/day	0.0852	0.0789
	Variable Charges			
	Weekends	$/kWh	0.02527	-
	Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm)	$/kWh	0.10154	-
	Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm)	$/kWh	0.07604	-
	Off Peak (Mon to Fri, 10:00pm to 3:00am)	$/kWh	0.00980	-
	Super Off Peak (Anytime between 3:00am to 5:00am)	$/kWh	-	-
Residential Low User (approx 118,133 connections)				
	Uncontrolled Charges			
	Residential Connection - Fixed Daily Charge - Uncontrolled	$/con/day	0.5998	0.7500
	Weekends - Uncontrolled	$/kWh	0.03012	0.03913
	Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm) - Uncontrolled	$/kWh	0.12020	0.15611
	Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm) - Uncontrolled	$/kWh	0.07007	0.09101
	Off Peak (Mon to Fri, 10:00pm to 3:00am) - Uncontrolled	$/kWh	0.00558	0.00721
	Super Off Peak (Anytime between 3:00am to 5:00am) - Uncontrolled	$/kWh	-	-
	Controlled Charges			
	Residential Connection - Fixed Daily Charge - Controlled	$/con/day	0.5036	0.6078

	Weekends - Controlled	$/kWh	0.03012	0.03913
	Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm) - Controlled	$/kWh	0.12020	0.15611
	Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm) - Controlled	$/kWh	0.07007	0.09101
	Off Peak (Mon to Fri, 10:00pm to 3:00am) - Controlled	$/kWh	0.00558	0.00721
	Super Off Peak (Anytime between 3:00am to 5:00am) - Controlled	$/kWh	-	-
Residential Standard User (approx 78,755 connections)				
	Uncontrolled Charges			
	Residential Connection - Fixed Daily Charge - Uncontrolled	$/con/day	0.5998	1.1613
	Weekends - Uncontrolled	$/kWh	0.03012	0.03109
	Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm) - Uncontrolled	$/kWh	0.12020	0.12458
	Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm) - Uncontrolled	$/kWh	0.07007	0.07260
	Off Peak (Mon to Fri, 10:00pm to 3:00am) - Uncontrolled	$/kWh	0.00558	0.00582
	Super Off Peak (Anytime between 3:00am to 5:00am) - Uncontrolled	$/kWh	-	-
	Controlled Charges			
	Residential Connection - Fixed Daily Charge - Controlled	$/con/day	0.5036	1.0191
	Weekends - Controlled	$/kWh	0.03012	0.03109
	Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm) - Controlled	$/kWh	0.12020	0.12458
	Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm) - Controlled	$/kWh	0.07007	0.07260
	Off Peak (Mon to Fri, 10:00pm to 3:00am) - Controlled	$/kWh	0.00558	0.00582
	Super Off Peak (Anytime between 3:00am to 5:00am) - Controlled	$/kWh	-	-

Small General Connection (approx 11,444 connections)				
	Uncontrolled Charges			
	Small Connection up to 15 kVA - Fixed Daily Charge - Uncontrolled	$/con/day	0.9408	1.5338
	Weekends - Uncontrolled	$/kWh	0.03012	0.02550
	Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm) - Uncontrolled	$/kWh	0.12020	0.10216
	Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm) - Uncontrolled	$/kWh	0.07007	0.05953
	Off Peak (Mon to Fri, 10:00pm to 3:00am) - Uncontrolled	$/kWh	0.00558	0.00477
	Super Off Peak (Anytime between 3:00am to 5:00am) - Uncontrolled	$/kWh	-	-
	Controlled Charges			
	Small Connection up to 15 kVA - Fixed Daily Charge - Controlled	$/con/day	0.7367	1.3967
	Weekends - Controlled	$/kWh	0.03012	0.02550
	Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm) - Controlled	$/kWh	0.12020	0.10216
	Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm) - Controlled	$/kWh	0.07007	0.05953
	Off Peak (Mon to Fri, 10:00pm to 3:00am) - Controlled	$/kWh	0.00558	0.00477
	Super Off Peak (Anytime between 3:00am to 5:00am) - Controlled	$/kWh	-	-
Medium General Connection (approx 11,832 connections)				
	Uncontrolled Charges			
	Medium Connection 16 kVA up to 69 kVA - Fixed Daily Charge - Uncontrolled	$/con/day	1.0071	2.7204
	Weekends - Uncontrolled	$/kWh	0.03012	0.02124

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	Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm) - Uncontrolled	$/kWh	0.12020	0.08511
	Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm) - Uncontrolled	$/kWh	0.07007	0.04961
	Off Peak (Mon to Fri, 10:00pm to 3:00am) - Uncontrolled	$/kWh	0.00558	0.00398
	Super Off Peak (Anytime between 3:00am to 5:00am) - Uncontrolled	$/kWh	-	-
	Controlled Charges			
	Medium Connection 16 kVA up to 69 kVA - Fixed Daily Charge - Controlled	$/con/day	0.8658	2.5840
	Weekends - Controlled	$/kWh	0.03012	0.02124
	Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm) - Controlled	$/kWh	0.12020	0.08511
	Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm) - Controlled	$/kWh	0.07007	0.04961
	Off Peak (Mon to Fri, 10:00pm to 3:00am) - Controlled	$/kWh	0.00558	0.00398
	Super Off Peak (Anytime between 3:00am to 5:00am) - Controlled	$/kWh	-	-
Large General Connection (approx 4,263 connections)				
	Uncontrolled Charges			
	Large Connection >70 kVA - Fixed Daily Charge - Uncontrolled	$/con/day	3.9718	11.9824
	Weekends - Uncontrolled	$/kWh	0.03012	0.01755
	Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm) - Uncontrolled	$/kWh	0.12020	0.07033
	Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm) - Uncontrolled	$/kWh	0.07007	0.04099
	Off Peak (Mon to Fri, 10:00pm to 3:00am) - Uncontrolled	$/kWh	0.00558	0.00329

	Super Off Peak (Anytime between 3:00am to 5:00am) - Uncontrolled	$/kWh	-	-
	Controlled Charges			
	Large Connection >70 kVA - Fixed Daily Charge - Controlled	$/con/day	3.2386	11.8382
	Weekends - Controlled	$/kWh	0.03012	0.01755
	Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm) - Controlled	$/kWh	0.12020	0.07033
	Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm) - Controlled	$/kWh	0.07007	0.04099
	Off Peak (Mon to Fri, 10:00pm to 3:00am) - Controlled	$/kWh	0.00558	0.00329
	Super Off Peak (Anytime between 3:00am to 5:00am) - Controlled	$/kWh	-	-
Two-way Power Flow (approx 2,000 connections)				
	Residential Two-way Power Flow			
	Residential Connection Fixed Daily Charge	$/con/day	-	0.7500
	Residential Consumption Weekends	$/kWh	-	0.03908
	Residential Consumption Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm)	$/kWh	-	0.21883
	Residential Consumption Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm)	$/kWh	-	0.09998
	Residential Consumption Off Peak (Mon to Fri, 10:00pm to 3:00am)	$/kWh	-	0.00360
	Residential Consumption Super Off Peak (Anytime between 3:00am to 5:00am)	$/kWh	-	-
	Residential Injection Weekends	$/kWh	-	-
	Residential Injection Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm)	$/kWh	-	(0.14548)
	Residential Injection Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm)	$/kWh	-	-

	Residential Injection Off Peak (Mon to Fri, 10:00pm to 3:00am)	$/kWh	-	-
	Residential Injection Super Off Peak (Anytime between 3:00am to 5:00am)	$/kWh	-	-
	Commercial Two-way Power Flow			
	Commercial Connection Fixed Daily Charge	$/con/day	-	1.4453
	Commercial Consumption Weekends	$/kWh	-	0.02520
	Commercial Consumption Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm)	$/kWh	-	0.19643
	Commercial Consumption Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm)	$/kWh	-	0.06471
	Commercial Consumption Off Peak (Mon to Fri, 10:00pm to 3:00am)	$/kWh	-	0.00236
	Commercial Consumption Super Off Peak (Anytime between 3:00am to 5:00am)	$/kWh	-	-
	Commercial Injection Weekends	$/kWh	-	-
	Commercial Injection Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm)	$/kWh	-	(0.08036)
	Commercial Injection Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm)	$/kWh	-	-
	Commercial Injection Off Peak (Mon to Fri, 10:00pm to 3:00am)	$/kWh	-	-
	Commercial Injection Super Off Peak (Anytime between 3:00am to 5:00am)	$/kWh	-	-
Irrigation connections (approx 1,050 connections)				
	Capacity Charge	$/kW/day*	0.1897	0.6397
	Power factor correction rebate	$/kVAr/day*	(0.11967)	(0.13588)
	Interruptibility rebate	$/kW/day*	(0.02962)	(0.03365)
	Weekends	$/kWh	0.03012	0.01350

	Peak (Mon to Fri, 7:00am to 11:00am and 5:00pm to 10:00pm)		$/kWh	0.12020	0.05410
	Shoulder (Mon to Fri, 5:00am to 7:00am and 11:00am to 5:00pm)		$/kWh	0.07007	0.03152
	Off Peak (Mon to Fri, 10:00pm to 3:00am)		$/kWh	0.00558	0.00253
	Super Off Peak (Anytime between 3:00am to 5:00am)		$/kWh	-	-
		* applied from 1 October to 31 March only			
Major customer and embedded network connections (approx 431 connections)					
	Fixed charge		$/con/day	20.0000	23.8045
	Fixed charge (additional connections)		$/con/day	15.0000	17.8534
	Extra switches		$/switch/day	3.90000	4.64187
	11kV Metering equipment		$/con/day	5.30000	6.30819
	11kV Underground cabling		$/km/day	4.70000	5.59405
	11kV Overhead lines		$/km/day	3.50000	4.16578
	Transformer capacity		$/kVA/day	0.01183	0.01403
	Peak charge (control period demand)		$/kVA/day	0.29744	0.36643
	Nominated maximum demand		$/kVA/day	0.09923	0.11813
	Metered maximum demand		$/kVA/day	0.09248	0.11128
Export credits (approx 12 connections)					
	0 - 30kW generation				
		Anytime credits (without PV), *or*	$/kWh	0.0028	Withdrawn
		Anytime credits (with PV), *or*	$/kWh	-	Withdrawn
	0 - 30kW generation2				
		Peak period credits (with or without PV)	$/kWh	0.0095	Withdrawn
	30 - 750kW Control period credits				

	plus	- real power, plus	$/kW/day	0.0676	0.0890
		- reactive power5	$/kVAr/day	0.0222	0.0293
Notes					

1. Full details on how we apply these prices are included in our Pricing Policy document, available on our website.

2. The applicable price category is recorded against each connection ICP on the Electricity Authority's registry, and the price component is used in our mandatory 'electricity information exchange protocol' files.

3. Weekend means all trading periods except for Super Off Peak between 3am -5am.

4. Where an ICP has a 'non-communicating' meter for a period of greater than 40 working days consumption (kWh) at that ICP will be allocated using the profile of an average residential consumer. Specifically, 26% of that ICPs consumption will be allocated to the Weekend, 32% to the Peak, 24% to the Shoulder, 13% to Off-peak, and 5% to Supper Off-peak.

Export credit schedule for Orion NZ Ltd					
(applicable from 1 April 2025)					
					(excluding GST)
Generator rated output	**Period applied**	**Credit prices**	**Price Component Code**[3]		**Unit of measure**
0 - 30kW generation[2]					
Anytime credits (without PV), or	Anytime (24 hours, 7 days)	Withdrawn	EXPA		$/kWh
Anytime credits (with PV)		Withdrawn	EXPAPV		$/kWh
0 - 30kW generation[2]					
Peak period credits (with or without PV)	Chargeable peak period (Mon to Fri 7am to 11am and 5pm to 10pm)	Withdrawn	EXPPP		$/kWh
30 - 750kW Control period credits[4]					
- real power, plus	Chargeable control period	(0.0890)	EXPCP1		$/kW/day
- reactive power[5]		(0.0293)	EXPCP2		$/kVAr/day

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Appendix B – Overview of the regulatory framework

B1. Regulatory background

We are a supplier of electricity distribution lines services. Accordingly, our revenues and prices are regulated by the Commerce Commission (the economic regulator) and the Electricity Authority (the electricity market regulator). Table 25 provides a summary of how these two regulators give effect to how much revenue we can earn and how we set our prices

Table 25: Summary of the regulatory functions around revenues and prices by the regulators

Regulator	Regulation	Purpose	Regulatory mechanism
Commerce Commission	Part 4 of the Commerce Act	Sets the price and quality path (how much revenue a distributor can collect)	Price Path Determination
		Sets reporting and disclosure requirements (the information about prices that a distributor must publicly disclose)	Information Disclosure Determination
Electricity Authority	Electricity Industry Act 2010	Provides terms and conditions for applying prices to retailers	The Electricity Participation Code and Default Distribution Agreement
		Provides guidance on developing pricing structures to reflect the true costs of providing distribution services	Distribution Pricing Principles

B2. Commerce Act 1986

Electricity distribution is a regulated service under Part 4 of the Commerce Act 1986 (the Act) the Commission regulates markets where competition is limited, including electricity distribution services. The purpose of Part 4 is to promote the long-term benefits of consumers by fostering outcomes consistent with competitive markets thereby ensuring that distributors have incentives to innovate, invest, improve efficiency, and provide services at a quality that consumers demand. Table 26 summarises the two ways the Commission regulates revenues of distributors.

Table 26: How the Commission regulates revenues for electricity distribution services

Price-quality regulation	The Commission regulates the price (how much a consumer pays for the service) and quality (the level of quality it must provide) to ensure distributors face incentives that exist in a workably competitive market. The Commission sets a price-quality path determination which provides how much revenue a distributor can collect and the service quality it must provide.

Information disclosure	The Commission regulates what information distributors must publicly disclose about its operating and business performance. This allows the Commission, stakeholders, and the public to judge whether the purpose of Part 4 of the Commerce Act are being met. The information that distributors must disclose publicly is prescribed by the Commission through the Information Disclosure Determination. This Pricing Methodology is a requirement of that determination.

B2.1 Price-quality regulation

We are subject to price and quality regulation under the Electricity Distribution Services Default Price-Quality Path Determination 2025 (DPP Determination 2025) for the 5-year regulatory period from 1 April 2025 to 31 March 2030. Table 27 provides an overview of the three components of the price path.

Table 27: Overview of the three components of the price path

Component of the price path	**What the price component recovers**
Distribution price component	The cost of operating the electricity distribution network and providing electricity distribution services.
Pass-through price component	The costs for other external services that the distributors then pass through to consumers. These costs include council rates, electricity regulation levies and transmission costs. These costs are largely outside the control of the distributors.
Recoverable price component	Recoverable costs are in-period adjustments to distribution service costs. Recoverable costs include incentive payments and penalties, wash-ups for differences between forecasts and actual pricing inputs, delayed recovery of revenue from price smoothing and approved innovation allowances cost recovery.

Before the start of each regulatory period, the Commission determines the total amount of allowable revenue that a non-exempt distributor is allowed to collect from its consumers. Allowable revenue comprises of ‘building blocks’ which include operating expenditure, asset depreciation, tax expenses and an industry benchmarked rate of return on capital employed. Once the building blocks are determined for each year of the regulatory period, the annual cost amounts are aggregated and smoothed over the regulatory period as forecast net allowable revenue.

The DPP Determination 2025 sets our forecast net allowable revenue to be collected from distribution prices for each year of the regulatory period starting 1 April 2025 and ending 31 March 2030. A mechanism at the end of each pricing year allows for any differences between forecast allowable revenue and actual revenue to be washed-up in subsequent years with a time value of money adjustment.

Pass-through price components recover the actual pass-through and recoverable costs that we incur. A mechanism at the end of each pricing year allows for any differences between pass-through and recoverable costs and pass-through price revenues to be washed up in subsequent years with a time value of money adjustment.

The prices provided in this Price Methodology are compliant with the DPP Determination 2025 for the first Assessment Period, i.e., the year commencing 1 April 2025.

B2.2 Information disclosure

We are also subject to information disclosure regulation under Part 4[16] of the Act. The purpose of information disclosure regulation is to ensure that interested persons have sufficient information readily available for them to assess whether the purpose of Part 4 of the Act is being met. Each year before the regulatory year begins and after it ends, we make several disclosures prescribed by the ID Determination: including publicly disclosing a pricing methodology before the start of the disclosure year commencing 1 April. The requirements of the ID Determination relating to pricing methodologies are set in Appendix C.

B3. Electricity Industry Act 2010

The Electricity Act 2010 provides the framework for the regulation of the electricity industry. The Act is enacted via The Electricity Industry Participation Code 2010 (Code) which provides the rules that govern the New Zealand electricity market. The Authority is the regulator of the Electricity Industry Act 2010 and the Code.

B3.1 Electricity Authority's price reform

The Electricity Authority is reforming prices for transmission and distribution services.[17] The intent of the reform is to provide prices that are fully cost reflective of the underlying costs of providing lines services to consumers. Prices influence people's and businesses' use of electricity and the investments they, distributors, Transpower and others in the sector make. Cost-reflective price signals support consumers and the industry to make efficient infrastructure investments which will help reduce the size of any future price increases.

Ensuring efficient investments in infrastructure will be especially important as New Zealand Emissions Reduction Programme increases electricity demand and future investment requirements.

B3.1.1 Transmission Pricing Methodology (TPM)

In April 2022 the Authority completed its review of the Transmission Pricing Methodology (TPM). The TPM, effective from 1 April 2023, determines how Transpower recovers its maximum allowable revenue from its transmission customers through transmission charges.[18] Distributors pass through these transmission costs to retailers and direct billed consumers by replicating as close as is practicable the allocation methodology used to assign the transmission costs to them.[19]

[16] Section 54F of the Commerce Act 1986

[17] The Electricity Authority's price reform is for methods used to calculate the unit price which pass costs on to consumers, not the total amount of revenue that is allowed to be collected, which is provided by the Commerce Act 1986 and is the responsibility of the Commission.

[18] Transpower's maximum allowable revenue is set by the Commerce Commission to reflect the annual cost of owning and operating the national electricity transmission network (the grid).

[19] More information about the TPM can be found in the Transpower New Zealand's, Guide to the TPM, available on its website.

B3.1.2 Distribution Pricing Reform

To assist distributors, interpret and apply the distribution pricing principles (discussed in more detail in Appendix C) the Authority also publish a Distribution Pricing Practice Note[20]. Further, the Authority developed a scorecard to 'monitor and comment on distributor's pricing structure and pricing reform.' The most recent scorecard assessed the progress of 1 April 2023 pricing.[21] In that scorecard we were assessed at an overall score of 4.1 out of 5, with five specific expectations of progress identified—

- Focus area 1: Roadmaps responding to future network congestion
- Focus Area 2: First mover disadvantage in new and expanded connections
- Focus Area 3: Pass-through of new transmission charges
- Focus Area 4: Phase-out of low fixed charge (LFC) regulations
- Focus Area 5: Recovery of fixed costs through use-based charges[22]

We put a strong focus on pricing reforms to progress these five areas for our 1 April 2024 prices. Table 28 provides a snapshot of the progress we have made on meeting the Authority's pricing reforms in 2024.

Table 28: Snapshot of our progress on meeting the Authority's expected pricing reforms in 2024

Authority's Expectation	How we align
Distributors' roadmaps responding to future network congestion	Our roadmap initially targets congestion reducing measures for our largest consumer segments first, including: • *Now* | Target large scale consumer network utilisation among Majors and GEN(GC3) by expanding access to interruptability rebate that currently applies to irrigators • *Now* | Support price mode innovators by trialling retailer aggregation prices for residential connections • *Next* | Activate commercial and industrial consumer demand management and response with reward prices by establishing variable demand pricing
Distributors' response to first mover disadvantage (FMD) issues	As part of phase 2 of our new connections and extensions methodology, we will consider implementation of a Pioneer Scheme for consumer-funded network extension assets to overcome first mover disadvantage via rebates from subsequent connections that occur within a reasonable period. This will involve a comprehensive assessment of technical, financial, and regulatory aspects. Additionally, we will address regulatory compliance, risk management strategies, and implement effective communication channels to keep stakeholders informed and engaged throughout the process.
Pass-through of transmission charges	We will continue to apply transmission pass through per our transition constraint identified in *Our 1 April 2027 pricing goals* at section 4.6.

[20] Electricity Authority, Distribution Pricing: Practice Note, Second Edition v 2.w, 2022 — October 2002.

[21] Electricity Authority, Distribution pricing scorecards 2023, Information paper, 10 October 2023.

[22] Electricity Authority, Orion — Distribution pricing scorecard 2023, 10 October 2023.

Authority's Expectation	How we align
The phase-out of the low fixed charge (LFC) price regulations	We are in the process of transitioning our legacy residential LFC prices under the regulated phase-out timeline, per our transition constraint identified in *Our 1 April 2027 pricing goals* at section 4.6 and *B4. Low Fixed Charge Regulations* below on page 82. In our 2023 pricing methodology we introduced the disaggregation of our general connections consumer segment to allow better targeting of the transition, by segmenting into: • Residential connections • General Group 1 (GC1) Small business • General Group 2 (GC2) Small and medium enterprises (SMEs) • General Group 3 (GC3) Commercial and industrial (C&I) In 2024 moved to time-of-use pricing and retired our Weekdays (Mon to Fri, 7am – 9pm) and Nights & weekends (Sat & Sun) prices. To further support the transition, this pricing year, we have introduced a new general pricing category Residential Standard User with a higher fixed daily price and lower volumetric price than the Residential Low User general pricing category.
Moving away from recovery of fixed costs through use-based charges	Moving away from recovering fixed costs through usage-based charges involves transitioning to pricing models where fixed capital and operational costs are not solely dependent on consumption volume. Instead, these costs can be offset through fixed fees (nominated capacity charge for Major Customers, Embedded Networks and Large Capacity Connections and nameplate rating for Irrigation) or tiered pricing structures reflecting the value of service access rather than just usage. This shift can promote fairness by guaranteeing that all users contribute to the maintenance of essential services, regardless of their consumption levels. Furthermore, it stabilises revenue streams, easing the financial strain on consumers with high usage and encouraging more efficient and equitable utilisation of resources.

The Authority decided not to complete a scorecard for 2024, so we are unclear as to the Authority's views as to the progress of our pricing reform.

In May 2024 the Authority released its Open Letter to Distributors[23] giving five new areas of focus for distributors, which were additional to those communicated in 2022. Table 29 provides a snapshot of our further progress on meeting the Authority's expected pricing reforms in 2025.

Table 29: Snapshot of our further progress on meeting the Authority's expected pricing reforms in 2025

Expectation	How we align
Allocate revenue transparently	Our current pricing methodology provides quantified details of our revenue allocations and our revenue outcomes relative to the calculated subsidy-free range.
Assign all ICPs to time-varying distribution prices (limited exceptions only)	All our general connections, streetlighting connections, and irrigation connections currently have prices with time-varying energy (kWh) charges. The price reform enablement limb of this pricing strategy is continuing our

[23] A copy of the Authority's open letter can be found on its website at https://www.ea.govt.nz/documents/4980/Open_letter_to_distributors_distribution_pricing_reform.pdf

Expectation	How we align
	transition to greater use of 30-minute ICP interval data to improve consumers' ability to benefit from responding to our time-varying distribution price signals. Our limited exceptions are our major customers and embedded network connections for whom we are less able to diversify the capacity utilisation risk on our network. These consumers' prices have maximum demand charges based on their nominated demand, metered demand and peak control-period demand.
Set peak rates based on a measure of Long-Run Marginal Cost	By aligning our peak rates with Long-Run Marginal Cost (LRMC), our pricing communicates the true cost of using the network during peak hours. This ensures that prices truly correspond to any additional expenses due to increased demand, such as the need for additional capacity or investments. Consumers will receive clear signals to shift their usage to off-peak periods, easing strain on the network. This promotes efficient resource allocation and encourages sustainable investment by ensuring sufficient recovery of peak-time usage, tested against our assumptions when setting peak prices.
Reduce off-peak and controlled rates	Our 2024 off-peak rates are well below our peak rates, and at 1.844 c/kWh are lower than the sector's 2024 weight average cited in the authority's letter. We consider this price differential is sufficient to motivate behavioural change whilst still spreading the recovery of our fixed costs in an equitable manner. As noted above, we will continue to monitor the table-up of ICP-based time-variable prices and the level of consumer load shifting behaviour we see and will adapt our prices if needed.
Improve price signalling	Our 2025 pricing methodology introduces further disaggregation of our general connection consumer segment to allow better targeting of price signals, and price shock management as LUFCR transition, by segmenting into: • Residential Standard User Controlled • Residential Standard User Uncontrolled • Residential Low User Controlled • Residential Low User Uncontrolled We will also transition to ICP based pricing.
Follow up on Asset Management Plan (AMP) reporting on readiness for increased electrification	These updates are provided separately to our pricing strategy; however, the LV system visibility measures we are pursuing within our AMP form part of the data set we are monitoring to identify future opportunities for our pricing design to support patterns of least cost electrification and distribution generation uptake.

We look forward to the Authority's 2025 assessment and gaining further insight into the progress of our pricing reforms.

B3.2 Default Distribution Agreements

The Default Distribution Agreement (DDA) provides the terms and conditions for the provision of distribution services to electricity retailers. The Code requires all distributors publish a default agreement with standardised terms for access to their networks.[24] Our DDA can be found on our

[24] Part 12 A, Distributor agreements, arrangements, and other provisions.

website[25]. When a retailer negotiates with us to trade on our network, we offer them the DDA in the first instance. We can negotiate an alternative agreement, and the parties have 20 business days to execute that agreement, or the DDA applies automatically.

Amongst other operations, the DDA prescribes the terms and conditions around the process that distributors must take when changing their prices, allocating price categories and price options to ICPs, and changing their pricing structures. The DDA requires us to consult with retailers on any material changes to our pricing structure including, the introduction of a new price category.

We have introduced three new price categories this pricing year: Residential standard user, Residential two-way power flow, and Commercial two-way power flow. We consulted with retailers extensively on the introduction of these new price categories. Their feedback was instrumental in the design of these prices, and we thank them for their time and insight.

B4. Low Fixed Charge Regulations

The Low Fixed Charge Regulations[26] require distributors to offer a pricing plan unique to residential consumers based on 9,000kWh per annum (deemed to be low users). This low-user pricing plan restricts the structure of prices for residential consumer by—

- allowing only one fixed charge
- capping the quantum of that fixed daily price, excluding GST
- requiring prices be set so that low users pay no more per year on a low-user plan than they would pay on any other price plan available to a residential user consuming 9,000kWh per annum
- prohibiting the use of tiered or stepped variable charges
- denying fees for special service, rebates, or discounts that are inconsistent with those offered to other consumers on our network.

In November 2021, the amendment regulations[27] came into force. The amendment regulations intend to phase out the low fixed charges over five years by allowing the regulated distributor tariff option to increase each year by 15 cents, as shown in Table 30.

Table 30: Timetable for the phasing out of the low fixed charges

Year	Pricing Year	Permissible change to fixed charges
1	1 April 2022 to 31 March 2023	15 cents increase to 30 cents
2	1 April 2023 to 31 March 2024	30 cents increase to 45 cents
3	1 April 2024 to 31 March 2025	45 cents increase to 60 cents
4	**1 April 2025 to 31 March 2026**	**60 cents increase to 75 cents**
5	1 April 2026 to 31 March 2027	75 cents increase to 90 cents

[25] https://www.oriongroup.co.nz/assets/Our-story/Regulatory-disclosures/Orion-default-distributor-agreement-v2-25-Nov-2024.pdf

[26] Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004.

[27] Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Amendment Regulations 2021

The phase-out of the low fixed charges has been an enabler in meeting the Authority's pricing reform expectations. Allowing distributors to increase the fixed charge has enabled us to pass-through transmission charges, increase the fixed proportion of cost recovery, and increase peak differentials, thereby sending stronger pricing signals to consumers.

The regulations will be revoked on 1 April 2027, which will further support us in completing our transition to more cost-reflective and efficient pricing.

B5. Related Pricing documents

In addition to this Pricing Methodology disclosure, the documents listed at Table 31 supports our prices and price setting process. Each can all be found on our website:[28]

Table 31: Other documents that support our Pricing Methodology

Document	Purpose
Annual Compliance Statement	Confirms that we have met revenue and quality expectations set out by the price quality path.
Annual Price Setting Compliance Statement	Confirm that our forecast prices have been set at a level to collect the allowances determined by the price-quality path set by the Commission.
Connections and Extensions Methodology	We collect revenue from our network lines charges (delivery prices) or from the consumer contributions paid towards new connections. The Extension and Connections Methodology is a regulatory disclosure which sets out how we calculate a consumer's contribution towards a new connection.
Network Pricing Schedule	The Network Pricing schedules provide stakeholders with our network lines charges and the terms and conditions of their application. Specifically, the Network Pricing Schedule provides: (a) Pricing structure (b) Pricing categories, and the eligibility criteria for each price category (c) Price options (if any) and (d) Unit prices.
Disclosure of prices	The disclosure of prices provides stakeholders (consumers, retailers and regulators) with prices and any price changes for the upcoming regulatory year. The disclosure of prices is a regulatory Information Disclosure requirement.
Line Charge Notices	The Line Charge Notice informs stakeholders of our prices for the upcoming regulatory year. We publish the Line Charge Notice on news websites, in print and on our website[29].
Pricing Roadmap	The Pricing Roadmap updates stakeholders about our intended pricing structures and/ or prices changes, together with expected timeframes and progress updates.

[28] https://www.oriongroup.co.nz/our-story/pricing

[29] https://www.oriongroup.co.nz/our-story/pricing

Appendix C – Demonstrating that we meet the Authority's Pricing Principles

The Authority's Distribution Pricing Principles 2019 provides pricing principles for distributors to apply when developing their pricing structures.

- 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);
    - reflecting the impacts of network use on economic costs;
    - reflecting differences in network service provided to (or by) consumers; and
    - encouraging efficient network alternatives.
- Where prices that signal economic costs would under-recover target revenues, the shortfall should be made up by prices that least distort network use.
- 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.
- Development of prices should be transparent and have regard to transaction costs, consumer impacts and uptake incentives.

In accordance with the ID Determination, we demonstrate our approach to setting prices are consistent with these Pricing Principles.

C1. Signalling the economic costs to serve

(a) Prices are to signal the economic costs of service provision, including by:

(i) being subsidy free (equal to or greater than avoidable costs, and less than or equal to standalone costs);

(ii) reflecting the impacts of network use on economic costs;

(iii) reflecting differences in network service provided to (or by) consumers; and

(iv) encouraging efficient network alternatives."

In line with the principle, we price to reflect the economic costs of providing our delivery service. We estimate the Long Run Average Incremental Cost (LRAIC) of investment in our network (see Table 24 above on page 52 for more detail on our approach) and we set a peak load-based price which reflects this.

We consider that the peak load based incremental cost of our current network provides a suitable surrogate for the incremental cost of meeting future load growth, in the long term. The fact that we must apply other additional price components, over and above the component that reflects the LRAIC, shows that our prices are greater than avoidable costs thereby meeting the first 'subsidy free' requirement in principle (a)(i).

Equally, prices are demonstrably lower than stand-alone costs on the basis that we provide a shared delivery service sized to meet the diversified load of customers, which is much smaller than the sum of individual load peaks. For example, we observe an average residential customer peak of 7.4 kW, but when looking at an entire residential suburb, the network peak equates to just 2.3 kW per household. An alternative approach to the assessment of stand-alone costs is also set out in the paragraphs below.

C1.1. Standalone subsidy free test

The Authority's 2019 Practice Note sets out an alternative basis for the subsidy free test. It focuses on consumer groups (or connection categories) rather than individual consumers. It also identifies avoidable cost as the costs that would reduce if a consumer group was not supplied with electricity, and the standalone costs as energy alternatives that would supply groups of consumers (such as micro-grids).

In this context we provide the estimated the avoidable and standalone cost boundaries for each consumer group at Table 32.

The estimated costs per kWh used in the stand-alone cost assessments are broadly based on information taken from recent economic assessments. Actual costs of these alternatives will vary from location to location, but the magnitude of the stand-alone cost shows that the subsidy free test is not sensitive to inaccuracies in this metric. The forecast revenue is taken from section 9.

In all cases, the revenue we receive is greater than avoidable costs and less than standalone costs, demonstrating that our pricing meets the subsidy free requirement in principle (a)(i).

Our cost allocation weights the allocation of assets that are installed for security of supply using the value that consumers place on "lost load". This helps us reflect the different willingness to pay for these back-up assets between different connection categories. We also provide a specific rebate scheme for irrigation consumers that elect to be first off following a capacity constraint caused by damage to or failure of our network.

We allocate Transpower's charges to each connection category based on our assessment of each category's use of the transmission system. Our distribution network load is characterised by summer (rural) and winter (urban) seasonal peaks. To the level of the lower summer peak, the transmission system is in place to meet both seasonal loads, and it would not be reasonable to view either winter or summer loads as "free" marginal additional loads. So, to the extent that all connection categories use the transmission service, we have split the costs equally between summer and winter peak demands. We then allocate the additional cost of meeting the higher winter peak only to connection categories that contribute to the winter peak. As a result, our price structure carries a lower winter demand price than Transpower applies to us but provides a more equitable (in terms of cost sharing) and stable structure.

Looking ahead, one of the primary strategic objectives we have established as part of our revised pricing strategy is to transition our pricing to enable consumers to efficiently use our network to share their local renewable energy resources.

Table 32: Avoidable and standalone costs

Consumer Group	Avoidable cost	($'000)	Forecast revenue ($'000)	Standalone cost	($'000)
Streetlighting	*Assuming that the separate lighting network assets could be abandoned*			*Reflecting geographic spread of load, an individual PV/Battery basis is assumed for each light*	
	Repair and maintenance costs	147			
	Cust. Service, billing, and admin	42		Estimated cost per lamp/per day	$0.08
	Transpower charges	54		Forecast number of lamps	54,332
	Total cost	**243**	**1,565**	**Total cost**	**4,287**
Residential Low User	*Assuming that the majority of the low voltage network assets could be abandoned*			*Based on subdivision sized micro-grid estimate of shared PV and battery*	
	Repair and maintenance costs	11,734			
	Cust. Service, billing, and admin	19,702		Estimated cost per kWh*	$0.42
	Transpower charges	25,620		Annual volume (MWh)	925,625
	Total cost	**57,056**	**107,707**	**Total cost**	**390,669**
Residential Standard User	*Assuming that the majority of the low voltage network assets could be abandoned*			*Based on subdivision sized micro-grid estimate of shared PV and battery*	
	Repair and maintenance costs	7,823			
	Cust. Service, billing, and admin	13,135		Estimated cost per kWh*	$0.42
	Transpower charges	17,080		Annual volume (MWh)	617,084
	Total cost	**38,038**	**71,805**	**Total cost**	**260,446**
Small General Connection	*Assuming that the majority of the low voltage network assets could be abandoned*			*Based on subdivision sized micro-grid estimate of shared PV and battery*	
	Repair and maintenance costs	812			
	Cust. Service, billing, and admin	1,195		Estimated cost per kWh*	$0.42
	Transpower charges	1,621		Annual volume (MWh)	78,563
	Total cost	**3,628**	**7,377**	**Total cost**	**33,158**

Consumer Group	Avoidable cost	($'000)	Forecast revenue ($'000)	Standalone cost	($'000)
Medium General Connection	*Assuming that the majority of the low voltage network assets could be abandoned*			*Based on subdivision sized micro-grid estimate of shared PV and battery*	
	Repair and maintenance costs	3,203			
	Cust. Service, billing, and admin	5,068		Estimated cost per kWh*	$0.42
	Transpower charges	6,836		Annual volume (MWh)	245,513
	Total cost	**15,107**	**28,333**	**Total cost**	**103,621**
Large General Connection	*Assuming that the majority of the low voltage network assets could be abandoned*			*Based on subdivision sized micro-grid estimate of shared PV and battery*	
	Repair and maintenance costs	4,505			
	Cust. Service, billing, and admin	7,909		Estimated cost per kWh*	$0.42
	Transpower charges	10,268		Annual volume (MWh)	299,384
	Total cost	**22,682**	**40,763**	**Total cost**	**126,358**
Two-way Power Flow	*Assuming that the majority of the low voltage network assets could be abandoned*			*Based on subdivision sized micro-grid estimate of shared PV and battery*	
	Repair and maintenance costs	225			
	Cust. Service, billing, and admin	415		Estimated cost per kWh*	$0.42
	Transpower charges	580		Annual volume (MWh)	17,482
	Total cost	**1,220**	**2,234**	**Total cost**	**7,342**
Irrigation connections	*Assuming that distribution transformers and associated LV network assets can be abandoned*			*Reflecting geographic spread load, an individual PV/Battery is basis is assumed for each installation*	
	Repair and maintenance costs	915			
	Cust. Service, billing, and admin	1,092		Estimated cost per kWh*	$0.28
	Transpower charges	1,705		Annual volume (MWh)	46,124
	Total cost	**3,712**	**6,021**	**Total cost**	**12,978**

Consumer Group	Avoidable cost	($'000)	Forecast revenue ($'000)	Standalone cost	($'000)
Major customer connections	*Assuming that distribution transformers and associated LV network assets can be abandoned*			*Based on industrial subdivision sized micro-grid estimate of shared PV and battery, with supplementary diesel generation*	
	Repair and maintenance costs	4,149			
	Cust. Service, billing, and admin	3,424		Estimated cost per kWh*	$0.28
	Transpower charges	4,237		Annual volume (MWh)	843,976
		11,810	**42,138**	**Total cost**	**237,472**
Large capacity connections	*Assuming that all dedicated assets can be abandoned*			*Based on large scale rurally located PV with battery storage*	
	Repair and maintenance costs	763			
	Cust. Service, billing, and admin	380		Estimated cost per kWh*	$0.14
	Transpower charges	2,178		Annual volume (MWh)	300,468
		3,321	**4,933**	**Total cost**	**42,272**

* An estimate of the savings associated with avoiding purchasing energy at the wholesale rate of 12c/kWh has been deducted from this cost to provide a basis that is comparable with the delivery cost.

C2. Recovery of Target Revenue shortfalls

(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 fixed and volume prices for general connections, and maximum demand-based prices for major customers, to collect the balance of our revenue requirement.

With the phasing out of the low fixed charge regulations, we will be gradually transitioning away from using volume-based pricing to collect the balance of our revenue requirement and instead recover a higher proportion from fixed charges. We have restructured the general connection fixed charges to ensure larger connections continue to contribute an equitable amount towards our overall revenue requirement.

Our capacity charge for major customers is based on the consumer's own peak, which is less subject to demand response than other measures.

C3. Price should reflect economic value and price/quality trade-offs

(c) Prices should be responsive to the requirements and circumstances of end users by allowing negotiation to:

(i) reflect the economic value of services; and

(ii) enable price/quality trade-offs.

We may recognise an alternative opportunity available to a major customer in close proximity to a grid exit point and may reduce the chargeable demands to approximate the lower-than-average cost to distribute over the shorter distance.

We also individually negotiate the pricing and charge structure directly with large capacity consumers. These connections have a significant impact on the network to which they connect such that significant additional investment by us is required. Consumers that elect to go ahead with the supply will do so on the basis that the service provides economic value.

Consumers in our major customer price category have the option to provide a range of their own connection equipment (transformers, switchgear, metering interfaces). Consumers that elect to use our service will do so on the basis that they provide economic value in comparison with the alternatives available. These factors align with principle (c)(i).

We also provide the opportunity to tailor the quality of the service to the specific needs of the consumer for major customer and large capacity connections. Major customers can elect to use additional connections and/or additional connection equipment which can provide enhanced security of supply. Services for large capacity connections are provided with specific security undertakings which are required by the consumer considering the costs associated with the services. These options align with principle (c)(ii).

As additional examples of our alignment with principle (c)(ii)—

- General consumers have options to select from a range of water heating options, each providing a different level of service, and coming at a different effective cost (based on varying contributions to our time-of-use (TOU) and weekend volume prices).

- Irrigation consumers can choose to allow us to turn off their pumps during system emergencies, and the lower service level is reflected in credits that we pay.

More generally, all consumers are free to invest in ways of achieving a higher quality service than that provided by our network. For example:

- some larger consumers have on-site backup generation capacity to achieve higher reliability than that provided by our network, and
- other consumers invest in relatively low-cost UPS devices (uninterruptible power supplies) for their critical loads, such as computers and cash registers.

C4. Price should be transparent

(d) Development of prices should be transparent and have regard to transaction costs, consumer impacts, and uptake incentives.

We openly disclose our pricing methodology and actively works to promote a stable and long-term pricing basis, recognising the impact on consumers and the impact on investment decisions they have made in response to our pricing. We also recognise that any material changes to pricing structure can impose costs (including transaction costs) on stakeholders, and in particular retailers. In relation to this:

i. our structure for major customers has been in place for more than 25 years while any other changes to are applied in a transitioned way;

ii. any significant changes are widely consulted on, and only made where we consider they will improve economic outcomes;

iii. material cost allocation changes are spread over a number of years to ease the impact on consumers; and

iv. price changes are only enacted after stakeholder consultation.

Our asset management plan sets out our longer-term plans for the network and this includes indications of key cost drivers. We conduct periodic major customer connections seminars at which pricing and other network related matters are discussed.

In terms of uptake incentives, when prices reflect costs, consumers are rewarded for their elections (such as loading levels, water heating options, election to participate in rebate schemes) at an appropriate level, and the uptake incentive is inherent in the prices.

Pricing development is primarily focussed on achieving efficient outcomes for the long-term benefit of consumers, but where possible we reduce retailer transaction costs. In recent years we have introduced a range of changes to simplify the application of our pricing.

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Appendix D — Commerce Commission information disclosure requirements

Table 33 references where in this Pricing Methodology, we have provided the information prescribed by the Commission in the ID Determination.

Table 33: Information Disclosure Requirements Compliance Matrix

IDD Section	Description of how addressed in this document
2.4.1 (1)	See IDD 2.4.3 below.
2.4.1 (2)	See sections 9, 10, and Appendix A.
2.4.1 (3)	See section 8 for non-standard contracts. See sections 5.5, 12 and 14 for distributed generation.
2.4.1 (4)	See section 5.2, 5.4 and Appendix E.
2.4.2	The methodology is publicly disclosed before the end of February each year for prices that apply from 1 April each year.
2.4.3 (1)	See sections 7 through 13.
2.4.3 (2)	See Appendix C.
2.4.3 (3)	See sections 9 and 10.
2.4.3 (4)	See section 9.
2.4.3 (5) (a) & (b)	See sections 7, 8 and 10.
2.4.3 (6)	See sections 5, 9.2 and 10.
2.4.3 (7)	See section 10.
2.4.3 (8)	See section 10.
2.4.4 (1) to (3)	See sections 3, 4, 5 and Appendix E.
2.4.5 (1) (a) to (c)	See section 8.
2.4.5 (2) (a) & (b)	See section 8.
2.4.5 (3) (a) & (b)	See sections 5.5, 12, 14 and Appendix A.

Appendix E – Pricing Strategy

E1. Our pricing strategy

The Board approved our refreshed pricing strategy in July 2024.

This pricing strategy and implementation roadmap set out how we intend to segment our consumers and structure our prices to them over coming years. This structure allows us to recover our permitted costs under the revenue allowance set by the Commerce Commission.

We intend this strategy to help retailers, consumers, new energy market participants, and other stakeholders understand how we are adapting our prices to:

- recover our efficient costs of servicing different consumer types
- empower consumers to respond to price signals that benefit them and all our consumers by helping lower our network costs, and
- support decarbonisation transition within our community.

E2. How we developed our pricing strategy

E2.1 Why we have refreshed our pricing strategy

Our pricing context is evolving. We last refreshed our pricing strategy in April 2021. Since that time the expectations of increased electrification of our consumers' energy needs, and the scale of benefits available from sending more targeted pricing signals have increased.

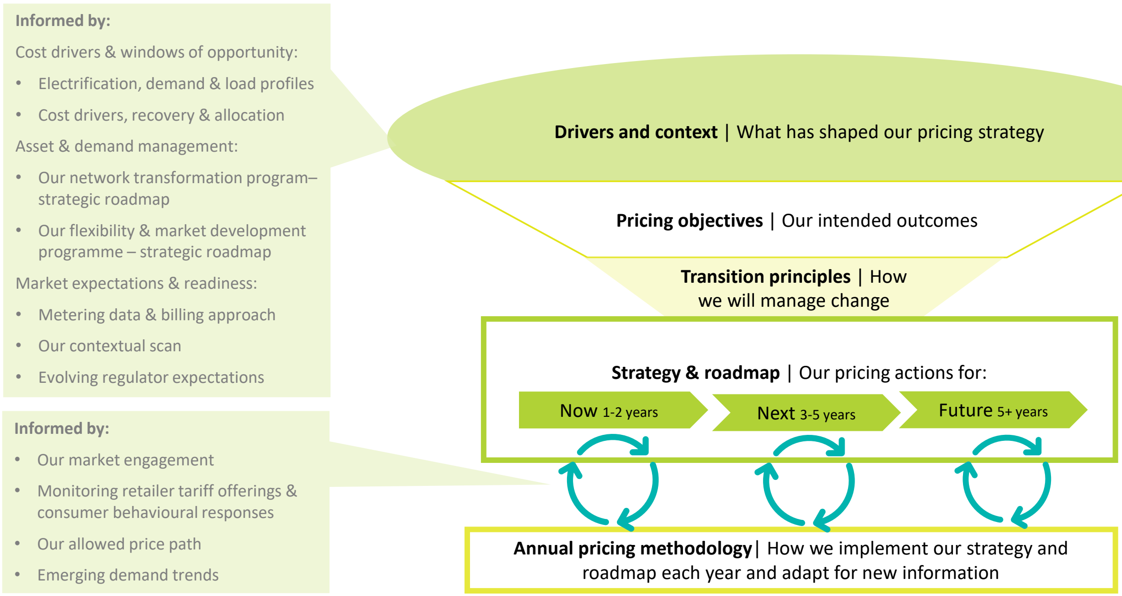
We sought to test and understand these trends through our stakeholder, consumer and consumer scan conducted in late 2023, which has informed this refreshed pricing strategy.

The Electricity Authority Te Mana Hiko has also evolved its expectations on our pricing practices, designs and evidence base. Since our 2021 pricing strategy the authority has published a practice note in 2022, progressed broad industry pricing consultation across 2023 and published open letters of its expectations in 2023 and 2024. Our new strategy addresses these expectations, and we set out in Table 28 the things we will monitor during implementation to dynamically refine our pricing actions for new information.

E2.2 How we have developed and will implement this pricing strategy

Figure 12 illustrates the methodical approach we have taken to refresh our pricing strategy, and how we intend to implement and refine it over the roadmap horizons. We have retained the horizons from our existing roadmap.

Figure 12: Our pricing strategy framework



E3. Our pricing objectives

Our pricing objectives recognise where we are now and where we need to get to. Our pricing objectives therefore seek to target 3 priorities:

1. Cost recovery and cost reflectivity | First we need prices that recover our allowed efficient cost of supply from each consumer segment in a manner reflecting our cost drivers.

2. Price reform enablement | Second, we need to establish pricing systems, data and processes that:

- support efficient price structures
- empower consumers and consumers to respond to price signals.

3. Price signalling and behavioural response | Finally, we need to ensure our prices are targeted by consumer and consumer type based on ability to respond and scale of the available cost and benefit sharing opportunities. Our prices should:

- send signals that can be responded to
- support efficient network utilisation amid growing electrification and two-way energy flows
- foster a growing flexibility services market
- leverage utility-mode control, where we have sight of the energy load or device, and the scale of benefits for sharing is sufficient to incentivise consumer choice to participate in control.

E3.1 Our transition principles

We recognise that how we transition our pricing is important to the effectiveness of our pricing strategy in realising our pricing objectives.

Our transition principles are our commitment to our consumers and consumers for how we intend to implement and refine our roadmap over time.

Our overarching transmission principles | Our roadmap seeks to:

- develop prices transparently and consider transaction costs, consumer impacts, and uptake incentives
- provide predictability for consumers to make investments with certainty and for retailers and aggregators to design market offers
- use the right tool for each consumer segment's required behaviours and controls, including simplicity where possible
- acknowledge the market value stacking opportunities and materiality when designing prices for cost recovery and behavioural response by understanding the interaction of our prices with the rest of the supply chain costs, benefits and market signals
- treat consumers and consumers equitably and ethically.

Our consumer segment specific principles | We recognise that some consumers will have specific needs amid pricing transitions. Our roadmap seeks to:

- consider impacts on vulnerable consumers within our residential connection's community
- provide signals for electrification and decarbonisation, particularly for commercial and industrial connections and EV charging
- provide signals to flexibility stakeholders who can access multiple value streams to attract coordinated and two-way CER connections.

E3.2 Our transition constraints

We intend to also transparently show how our pricing actions in the roadmap have been designed to address key transition and compliance constraints. Key constraints that will affect how we transition our prices are that our pricing should:

- comply with the Electricity Authority's distribution pricing principles and guidance on these
- comply with the phase-out of the low fixed charge price regulation until 1 April 2027
- manage bill impacts of the default price path for the 2025-26 to 2029-30 pricing period
- retain transmission pass through as regulated
- manage orderly scaling of new billing system functionality and retailer interfaces for ICP 30-minute interval data
- accommodate legacy accumulation meters out to 2030 which require legacy prices using our existing GXP deemed load profiles
- support our asset management strategy (including demand response controls) and investment plans as these evolve.

E4. Our roadmap by objective area

Our roadmap actions have been designed to respond to our drivers and context, advance our objectives, and take an orderly sequence considering our transition principles and constraints. The actions for each priority areas are set out below for each of our strategy horizons: Now—2025-2026, Next—2027-2030, and Future—2030+.

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E4.1 Cost recovery and reflectivity

Now	• Establish cost allocations based on more granular consumer segments • Review cost and revenue allocations for new Electricity Authority guidance and consider need for revenue rebalancing • Monitor locational and temporal cost drivers, including control period signals • Manage initial bill impacts of default price path 4 (DPP4)
Next	• Manage ongoing bill impacts of DPP4 • Monitor if reverse power flows are driving costs and require pricing signals • Monitor locational and temporal cost drivers, including control period signals
Future	• Monitor if reverse power flows are driving costs and require pricing signals • Monitor locational and temporal cost drivers, including control period signals

E4.2 Price reform enablement

Now	• Move from GXP deemed load profiles to ICP 30-minute interval billing to enable consumer behavioural rewards • Establish and implement regulatory protocols for consumption data files • Establish dynamic control provisions in new connection agreements • Develop industry-wide consumer personas and common flexibility language
Next	• Introduce opt-in prices that incentivise ICP 30-minute interval data sharing • Monitor regulatory changes for multiple trading relationships
Future	• Establish dynamic control network capability for mass market • If regulated, implement billing approach to accommodate multiple trading relationships

E4.3 Price signalling and behavioural response

Now	• Continue to promote time of use load shifting via super off-peak price window • Target large scale consumer network utilisation among Majors and GEN(GC3) by expanding access to interruptibility rebate that currently is available to irrigators • Support price mode innovators by trialling retailer aggregation prices for residential connections • Monitor retailer responses to existing price changes and levels of consumer response

Next	• Activate commercial and industrial consumer demand management and response with reward prices by establishing variable demand pricing • Progress retailer aggregation price trials and price designs • Monitor retailer responses to existing price changes and levels of consumer response
Future	• Support innovators by implementing opt-in variable demand pricing and interruptible supply prices for aggregators • Monitor retailer responses to existing price changes and levels of consumer response

E5. Things we will monitor during implementation

Our roadmap is intended to foreshadow both what we currently plan to do, and what we intend to monitor and respond to. This iterative approach will allow us to dynamically refine our pricing actions for new information and evolving market, consumer and regulator behaviours and expectations.

The monitoring and refinement aspect of our strategy will consider:

- Market dynamics, including:
  - retailer responses to existing price changes and levels of consumer response
  - the number of consumers billed on 30-minute interval ICP data
  - the level of retail price offering alignment to our time-varying distribution prices.
- Decarbonisation trends, including:
  - renewable distributed generation connections and their export and import profiles
  - patterns of high thermal load electrification among our major users
  - public EV charging connections and load profile, and willingness to participate in demand response.
- Network loads, constraints and utilisation trends, including:
  - whether and if so where and at what scales reverse power flows are driving costs and require pricing signals
  - locational and temporal cost drivers, including levels of consumer or aggregators response to control period signals versus uncontrolled time-variable price signals.

Appendix F – Allocation of the Revenue Required by GXP

Table 34: Allocation to the consumer group by cost driver at the Arthurs Pass GXP for the pricing year

Description	LIG	LOW	RSU	GEN(GC1)	GEN(GC2)	GEN(GC3)	2WAYRES	2WAYSME	IRR	MCC
No of ICP	1%	41%	28%	17%	12%	1%	-	-	-	-
Line Length (meters)	1%	34%	23%	12%	28%	3%	-	-	-	-
Installed Capacity (kW)	0%	34%	23%	12%	28%	3%	-	-	-	-
Asset Utilisation	0%	34%	23%	12%	28%	3%	-	-	-	-
Consumption (kWh)	2%	42%	28%	4%	11%	14%	-	-	-	-

Table 35: Allocation to the consumer group by cost driver at the Bromley GXP for the pricing year

Description	LIG	LOW	RSU	GEN(GC1)	GEN(GC2)	GEN(GC3)	2WAYRES	2WAYSME	IRR	MCC
No of ICP	0%	54%	36%	4%	5%	1%	0.5%	0.03%	-	0.1%
Line Length (meters)	0%	42%	28%	2%	10%	13%	0.4%	0.02%	-	5%
Installed Capacity (kW)	0%	42%	28%	2%	10%	13%	0.4%	0.02%	-	5%
Asset Utilisation	0%	42%	28%	2%	10%	13%	0.4%	0.02%	-	5%
Consumption (kWh)	1%	31%	21%	3%	8%	10%	0.4%	0.06%	-	26%

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Table 36: Allocation to the consumer group by cost driver at the Castle Hill GXP for the pricing year

Description	LIG	LOW	RSU	GEN(GC1)	GEN(GC2)	GEN(GC3)	2WAYRES	2WAYSME	IRR	MCC
No of ICP	0.4%	47%	31%	12%	7%	3%	-	-	-	-
Line Length (meters)	0.04%	37%	24%	7%	14%	18%	-	-	-	-
Installed Capacity (kW)	0.04%	37%	24%	7%	14%	18%	-	-	-	-
Asset Utilisation	0.04%	37%	24%	7%	14%	18%	-	-	-	-
Consumption (kWh)	2%	42%	28%	4%	11%	14%	-	-	-	-

Table 37: Allocation to the consumer group by cost driver at the Coleridge GXP for the pricing year

Description	LIG	LOW	RSU	GEN(GC1)	GEN(GC2)	GEN(GC3)	2WAYRES	2WAYSME	IRR	MCC
No of ICP	1%	42%	27%	12%	15%	2%	-	-	-	1%
Line Length (meters)	0.04%	35%	23%	7%	29%	7%	-	-	-	-
Installed Capacity (kW)	0.04%	35%	23%	7%	29%	7%	-	-	-	-
Asset Utilisation	0.04%	35%	23%	7%	29%	7%	-	-	-	-
Consumption (kWh)	0.44%	10%	7%	1%	3%	3%	-	-	-	77%

Table 38: Allocation to the consumer group by cost driver at the Hororata GXP for the pricing year

Description	LIG	LOW	RSU	GEN(GC1)	GEN(GC2)	GEN(GC3)	2WAYRES	2WAYSME	IRR	MCC
No of ICP	0.1%	41%	27%	11%	10%	4%	1%	0.04%	6%	0.1%
Line Length (meters)	0.02%	20%	13%	3%	10%	12%	0.4%	0.02%	27%	14%
Installed Capacity (kW)	0.02%	20%	13%	3%	10%	12%	0.4%	0.02%	27%	14%
Asset Utilisation	0.02%	20%	13%	3%	10%	12%	0.4%	0.02%	27%	14%
Consumption (kWh)	1%	26%	18%	2%	7%	9%	0.4%	0.07%	17%	20%

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Table 39: Allocation to the consumer group by cost driver at the Islington GXP for the pricing year

Description	LIG	LOW	RSU	GEN(GC1)	GEN(GC2)	GEN(GC3)	2WAYRES	2WAYSME	IRR	MCC
No of ICP	0.01%	53%	35%	4%	5%	2%	1%	0.05%	0.2%	0.2%
Line Length (meters)	0.1%	38%	25%	2%	9%	16%	1%	0.035	1%	7%
Installed Capacity (kW)	0.1%	38%	25%	2%	9%	16%	1%	0.03%	1%	7%
Asset Utilisation	0.1%	38%	25%	2%	9%	16%	1%	0.03%	1%	7%
Consumption (kWh)	1%	29%	19%	2%	8%	9%	1%	0.08%	1%	29%

Table 40: Allocation to the consumer group by cost driver at the Kimberley GXP for the pricing year

Description	LIG	LOW	RSU	GEN(GC1)	GEN(GC2)	GEN(GC3)	2WAYRES	2WAYSME	IRR	MCC
No of ICP	0.2%	41%	27%	10%	8%	2%	10%	1%	2%	-
Line Length (meters)	0.1%	31%	21%	5%	12%	15%	6%	0.3%	11%	-
Installed Capacity (kW)	0.1%	31%	21%	5%	12%	15%	6%	0.3%	11%	-
Asset Utilisation	0.1%	31%	21%	5%	12%	15%	6%	0.3%	11%	-
Consumption (kWh)	2%	40%	27%	3%	11%	13%	2%	0.4%	3%	-

Table 41: Allocation to the consumer group by cost driver at the Norwood GXP for the pricing year

Description	LIG	LOW	RSU	GEN(GC1)	GEN(GC2)	GEN(GC3)	2WAYRES	2WAYSME	IRR	MCC
No of ICP	0.022%	41%	28%	7%	11%	3%	0.4%	0.02%	10%	0.1%
Line Length (meters)	0.001%	28%	19%	3%	16%	12%	0.3%	0.01%	19%	2%
Installed Capacity (kW)	0.001%	28%	19%	3%	16%	12%	0.3%	0.01%	19%	2%
Asset Utilisation	0.001%	28%	19%	3%	16%	12%	0.3%	0.01%	19%	2%
Consumption (kWh)	1%	33%	22%	3%	9%	11%	0.1%	0.02%	13%	8%

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Appendix G – Historical quantities by GXP

Table 42: Quantities used to allocate the Required Revenue to the Arthurs Pass GXP for the pricing year

Consumer Group		ICPs / Supplies (Number)	Consumption (kWh)	Installed capacity (kVA)	Asset utilisation (kW)	Line length (meters)	RAB ($'000)	RAB Depreciation ($'000)
Streetlighting		1	12,653	5	3	20		
Residential Low User		68	283,420	955	668	3,840		
Residential Standard User		46	188,947	636	445	2,560		
Small General Connection		28	24,056	339	237	1,363		
Medium General Connection		20	75,174	779	545	3,133		
Large General Connections		1	91,669	75	53	302		
Residential Two-way Power Flow		-	-	-	-	-		
Commercial Two-way Power Flow		-	-	-	-	-		
Irrigation Connections		-	-	-	-	-		
Major Customer Connections		-	-	-	-	-		
Total		**164**	**675,919**	**2,788**	**1,952**	**11,218**		
Network	Sub transmission Lines						46,992	1,703
	Sub transmission Cables						60,405	1,804
	Zone Substation						103,789	4,948
	Distribution LV Lines						90,267	3,564
	Distribution LV cables						271,770	9,089
	Distribution substations and transformers						96,599	2,768
	Distribution switchgear						111,180	4,291
	Other network assets						24,650	1,163
Non-Network	Non-Network assets						35,530	2,893
Total							**841,181**	**32,223**

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Table 43: Quantities allocated to the Required Revenue at the Bromley GXP for the pricing year

Consumer Group		ICPs / Supplies (Number)	Consumption (kWh)	Installed capacity (kVA)	Asset utilisation (kW)	Line length (meters)	RAB ($'000)	RAB Depreciation ($'000)
Streetlighting		7	8,051,313	1,001	701	1,612		
Residential Low User		30,710	180,341,951	446,014	312,210	718,125		
Residential Standard User		20,474	120,227,967	297,343	208,140	478,750		
Small General Connection		2,248	15,306,706	25,109	17,576	40,428		
Medium General Connection		2,684	47,833,851	110,137	77,096	177,332		
Large General Connections		795	58,329,773	138,906	97,234	223,652		
Residential Two-way Power Flow		285	2,248,364	4,053	2,837	6,525		
Commercial Two-way Power Flow		15	373,942	195	136	314		
Irrigation Connections		-	-	-	-	-		
Major Customer Connections		58	152,020,567	48,256	33,779	77,697		
Total		**57,276**	**584,734,433**	**1,071,013**	**749,709**	**1,724,434**		
Network	Sub transmission Lines						18,048,794	654,157
	Sub transmission Cables						23,200,500	692,925
	Zone Substation						39,863,668	1,900,530
	Distribution LV Lines						34,670,075	1,368,693
	Distribution LV cables						104,382,978	3,491,137
	Distribution substations and transformers						37,102,441	1,063,004
	Distribution switchgear						42,702,431	1,648,091
	Other network assets						9,467,891	446,725
Non-Network	Non-Network assets						13,646,606	1,111,130
Total							**323,085,386**	**12,376,393**

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Table 44: Quantities allocated to the Required Revenue at the Castle Hill GXP for the pricing year

Consumer Group		ICPs / Supplies (Number)	Consumption (kWh)	Installed capacity (kVA)	Asset utilisation (kW)	Line length (meters)	RAB ($'000)	RAB Depreciation ($'000)
Streetlighting		1	28,409	2	2	37		
Residential Low User		120	636,339	1,843	1,290	32,028		
Residential Standard User		80	424,226	1,229	860	21,352		
Small General Connection		31	54,010	354	248	6,147		
Medium General Connection		17	168,782	708	496	12,299		
Large General Connections		8	205,817	906	634	15,746		
Residential Two-way Power Flow		-						
Commercial Two-way Power Flow		-						
Irrigation Connections		-						
Major Customer Connections		-						
Total		**257**	**1,517,584**	**5,042**	**3,530**	**87,610**		
Network	Sub transmission Lines						84,976	3,080
	Sub transmission Cables						109,231	3,262
	Zone Substation						187,683	8,948
	Distribution LV Lines						163,231	6,444
	Distribution LV cables						491,447	16,437
	Distribution substations and transformers						174,683	5,005
	Distribution switchgear						201,048	7,759
	Other network assets						44,576	2,103
Non-Network	Non-Network assets						64,250	5,231
Total							**1,521,123**	**58,269**

Table 45: Quantities allocated to the Required Revenue at the Coleridge GXP for the pricing year

Consumer Group	**ICPs / Supplies** (Number)	**Consumption** (kWh)	**Installed capacity** (kVA)	**Asset utilisation** (kW)	**Line length** (meters)	**RAB** ($'000)	**RAB Depreciation** ($'000)
Streetlighting	1	15,055	1	1	33		
Residential Low User	55	337,223	930	651	29,880		
Residential Standard User	36	224,815	620	434	19,920		
Small General Connection	16	28,622	176	123	5,657		
Medium General Connection	20	89,445	766	536	24,604		
Large General Connections	2	109,071	185	130	5,959		
Residential Two-way Power Flow	-	-	-	-	-		
Commercial Two-way Power Flow	-	-	-	-	-		
Irrigation Connections	-	-	-	-	-		
Major Customer Connections	1	2,621,044	-	-	-		
Total	**131**	**3,425,276**	**2,677**	**1,874**	**86,053**		
Network	Sub transmission Lines					45,118	1,635
	Sub transmission Cables					57,997	1,732
	Zone Substation					99,651	4,751
	Distribution LV Lines					86,668	3,421
	Distribution LV cables					260,936	8,727
	Distribution substations and transformers					92,749	2,657
	Distribution switchgear					106,747	4,120
	Other network assets					23,668	1,117
Non-Network	Non-Network assets					34,114	2,778
Total						**807,648**	**30,938**

Table 46: Quantities allocated to the Required Revenue at the Hororata GXP for the pricing year

Consumer Group	ICPs / Supplies (Number)	Consumption (kWh)	Installed capacity (kVA)	Asset utilisation (kW)	Line length (meters)	RAB ($'000)	RAB Depreciation ($'000)
Streetlighting	5	789,925	36	25	216		
Residential Low User	1,829	17,693,589	34,315	24,020	207,365		
Residential Standard User	1,220	11,795,726	22,876	16,013	138,243		
Small General Connection	495	1,501,761	5,925	4,148	35,808		
Medium General Connection	458	4,693,043	17,051	11,936	103,043		
Large General Connections	160	5,722,812	20,507	14,355	123,926		
Residential Two-way Power Flow	37	291,893	665	466	4,020		
Commercial Two-way Power Flow	2	49,859	26	19	160		
Irrigation Connections	263	11,553,046	45,252	31,676	273,461		
Major Customer Connections	5	13,105,221	23,684	16,579	143,124		
Total	**4,474**	**67,196,876**	**170,338**	**119,237**	**1,029,367**		
Network	Sub transmission Lines					2,870,556	104,040
	Sub transmission Cables					3,689,905	110,206
	Zone Substation					6,340,085	302,268
	Distribution LV Lines					5,514,074	217,683
	Distribution LV cables					16,601,506	555,245
	Distribution substations and transformers					5,900,928	169,065
	Distribution switchgear					6,791,573	262,119
	Other network assets					1,505,813	71,049
Non-Network	Non-Network assets					2,170,413	176,719
Total						**51,384,852**	**1,968,393**

Table 47: Quantities allocated to the Required Revenue at the Islington GXP for the pricing year

Consumer Group	ICPs / Supplies (Number)	Consumption (kWh)	Installed capacity (kVA)	Asset utilisation (kW)	Line length (meters)	RAB ($'000)	RAB Depreciation ($'000)
Streetlighting	12	29,469,666	2,864	2,005	6,335		
Residential Low User	82,240	660,093,214	1,297,128	907,989	2,868,693		
Residential Standard User	54,826	440,062,142	864,752	605,326	1,912,462		
Small General Connection	6,116	56,026,080	73,517	51,462	162,588		
Medium General Connection	7,692	175,082,947	317,159	222,011	701,421		
Large General Connections	3,059	213,500,446	553,050	387,135	1,223,111		
Residential Two-way Power Flow	1,464	11,549,491	30,576	21,403	67,620		
Commercial Two-way Power Flow	77	1,919,566	1,073	751	2,374		
Irrigation Connections	308	13,529,803	30,737	21,516	67,977		
Major Customer Connections	253	663,124,199	242,851	169,996	537,083		
Total	**156,047**	**2,264,357,557**	**3,413,707**	**2,389,595**	**7,549,663**		
Network	Sub transmission Lines					57,528,039	2,085,034
Network	Sub transmission Cables					73,948,389	2,208,602
Network	Zone Substation					127,059,934	6,057,676
Network	Distribution LV Lines					110,506,074	4,362,521
Network	Distribution LV cables					332,706,321	11,127,518
Network	Distribution substations and transformers					118,258,905	3,388,180
Network	Distribution switchgear					136,108,100	5,253,063
Network	Other network assets					30,177,595	1,423,873
Non-Network	Non-Network assets					43,496,671	3,541,575
Total						**1,029,790,027**	**39,448,041**

Table 48: Quantities allocated to the Required Revenue at the Kimberly GXP for the pricing year

Consumer Group	ICPs / Supplies (Number)	Consumption (kWh)	Installed capacity (kVA)	Asset utilisation (kW)	Line length (meters)	RAB ($'000)	RAB Depreciation ($'000)
Streetlighting	2	583,642	15	11	122		
Residential Low User	395	13,073,050	7,155	5,008	57,520		
Residential Standard User	263	8,715,367	4,770	3,339	38,346		
Small General Connection	97	1,109,588	1,052	737	8,459		
Medium General Connection	75	3,467,492	2,831	1,981	22,755		
Large General Connections	24	4,228,345	3,474	2,432	27,931		
Residential Two-way Power Flow	95	749,455	1,378	964	11,077		
Commercial Two-way Power Flow	5	124,647	66	46	530		
Irrigation Connections	19	834,631	2,517	1,762	20,235		
Major Customer Connections	-	-	-	-	-		
Total	**975**	**32,886,217**	**23,258**	**16,281**	**186,976**		
Network	Sub transmission Lines					391,944	14,206
	Sub transmission Cables					503,817	15,047
	Zone Substation					865,671	41,271
	Distribution LV Lines					752,888	29,722
	Distribution LV cables					2,266,758	75,813
	Distribution substations and transformers					805,708	23,084
	Distribution switchgear					927,316	35,790
	Other network assets					205,603	9,701
Non-Network	Non-Network assets					296,347	24,129
Total						**7,016,050**	**268,763**

Table 49: Quantities allocated to the Required Revenue at the Norwood GXP for the pricing year

Consumer Group	ICPs / Supplies (Number)	Consumption (kWh)	Installed capacity (kVA)	Asset utilisation (kW)	Line length (meters)	RAB ($'000)	RAB Depreciation ($'000)
Streetlighting	1	2,373,611	1	1	11		
Residential Low User	1,914	53,166,678	33,586	23,510	374,378		
Residential Standard User	1,276	35,444,452	22,391	15,673	249,585		
Small General Connection	339	4,512,576	4,014	2,810	44,740		
Medium General Connection	506	14,101,916	19,192	13,434	213,928		
Large General Connections	118	17,196,222	14,315	10,020	159,566		
Residential Two-way Power Flow	19	149,891	296	207	3,298		
Commercial Two-way Power Flow	1	24,929	13	9	148		
Irrigation Connections	460	20,206,849	22,500	15,750	250,805		
Major Customer Connections	5	13,105,221	1,814	1,270	20,220		
Total	**4,639**	**160,282,345**	**118,121**	**82,685**	**1,316,680**		
Network	Sub transmission Lines					1,990,582	72,146
Network	Sub transmission Cables					2,558,758	76,422
Network	Zone Substation					4,396,520	209,607
Network	Distribution LV Lines					3,823,725	150,952
Network	Distribution LV cables					11,512,285	385,034
Network	Distribution substations and transformers					4,091,988	117,238
Network	Distribution switchgear					4,709,605	181,766
Network	Other network assets					1,044,203	49,269
Non-Network	Non-Network assets					1,505,069	122,545
Total						**35,632,734**	**1,364,979**

Appendix I - Directors' certification of pricing methodology

In accordance with clause 2.9.1 of section 2.9 of the Commerce Commission's information disclosure determination for electricity distribution businesses the certification of our pricing methodology document is included below.

We, Paul Jason Munro and Michael Earl Sang, being directors of Orion New Zealand Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

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

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

Paul Jason Munro **Michael Earl Sang**

28 February 2025