Pricing Methodology

Pursuant to the Electricity Distribution Information Disclosure Determination 2012.

Effective from 1st April 2026

Draft – a final certified version will be published
https://www.eanetworks.co.nz/about-us/disclosures
by 28 February 2026

Contents

Definitions and common acronyms

Assets	The hardware, equipment and plant that is part of our electricity distribution network.
Code	The Electricity Industry Participation Code, available at https://www.ea.govt.nz/code-and-compliance/the-code/. These are the regulations that govern electricity industry participants obligations and responsibilities.
Connection Category	Customer segments that have similar electricity requirements and usage attributes and are grouped together for pricing. Referenced as a "consumer group" in the IDs.
Customer	An end user who has a premise or plant connected to the electricity distribution network.
DPP	Default price-quality path, the form of price regulation that applies to EA Networks. DPP4 refers to the 5-year regulatory period that runs from 1 April 2025 to 31 March 2030.
Electricity Authority	The "Authority" is an independent Crown entity that regulates and oversees New Zealand's electricity industry. Its core purpose is to promote competition, ensure reliable supply, and support the efficient operation of the electricity market for the long-term benefit of consumers.
FY26, FY27	FY stands for financial year, and for us FY27 means the year ending on 31 March 2027.
GXP	Grid exit point, the point where EA Networks' electricity distribution network connects to Transpower's transmission network.
ICP	Installation control point or "connection", a point of supply or connection to our network, which is represented by a unique ICP number in the format 0000026335EA378.
ID	The Electricity Distribution Information Disclosure Determination 2012 available at https://www.comcom.govt.nz/regulated-industries/electricity-lines/information-disclosure-requirements-for-electricity-distributors/current-information-disclosure-requirements-for-electricity-distributors which sets out the requirements for this disclosure document.
kVA	Kilovolt amperes, a measure of apparent demand (which is the vector combination of real demand in kW and reactive demand in kVAr).
kVAr	Kilovolt amperes reactive, a measure of reactive demand (where current flows are out of step with alternating voltage, using up available capacity without delivering real power).
kW	Kilowatts, a measure of electrical demand, or the rate at which energy is being used (an average of this can also be represented as kWh/h) – in other words, how fast energy is being used.
kWh	Kilowatt hours, a measure of energy and the basis used to apply volume charges (also called "units" of electricity) – in other words, how much energy is used.
Retailer	The entity that charges customers for their connection and electricity supply.
TPM	The Electricity Authority's Transmission Pricing Methodology
VOLL	Value of lost load, the amount that we assess customers in each connection category are willing to pay (on average) to avoid a power cut – the financial equivalent to the adverse impact of a power outage.

1. Introduction

1.1. Purpose

This document explains how we derive pricing for the electricity delivery service that we provide in Mid Canterbury. It explains how we establish connection categories, our overall costs, how we assign these costs to the different connection categories, and how we structure prices to meet those costs.

Specifically, this document is provided to meet clause 2.41 of the Electricity Distribution Information Disclosure Determination 2012 (the IDs). It also sets out our road map for pricing reform to meet the changing demands from new technology and our decarbonisation transition.

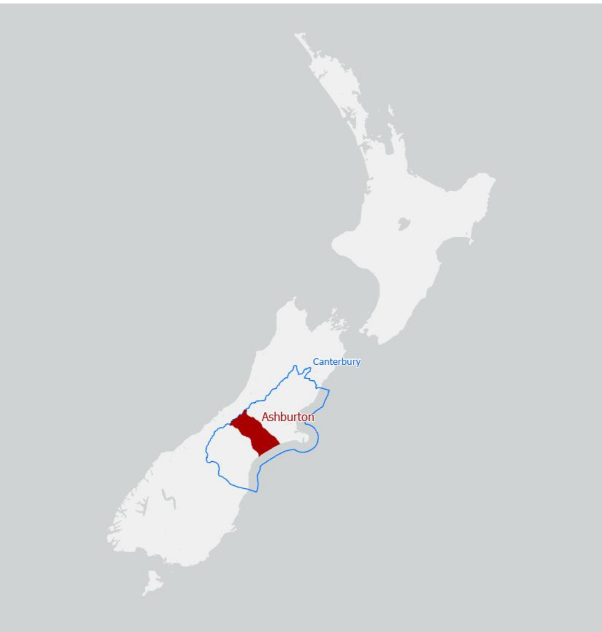
1.2. About EA Networks

EA Networks is the trading name of Electricity Ashburton Limited. We own and operate the electricity distribution network located in Mid Canterbury. We are a consumer owned cooperative, with every connected customer entitled to own shares in the company.

Our network delivers electricity to households and businesses across an area of about 3,500km^2, between the Rangitata River in the south, the Rakaia River in the north, and the foothills of the Southern Alps in the west. Distribution lines also run into three river gorges through the foothills.

From a network engineering perspective there are two general network designs: rural and urban.

The rural distribution network configuration is predominantly long radial overhead feeders with some interconnection to adjacent feeders and substations.



The urban 11kV distribution network is based upon a similar principle to the rural arrangement, except the network is largely underground cable, the interconnections are more frequent, and the overall feeder lengths are significantly shorter.

In addition to receiving power from Transpower's grid, we also have a growing number of large-scale renewable embedded generators:

- Lauriston solar 47MW
- Highbank hydro at 28MW
- Gartartan solar 6.5MW
- Fairton Solar 4.3MW
- Montalto hydro is 1.6MW
- Cleardale hydro at 1MW
- Lavington hydro at 0.5MW

2. Summary and outcomes

This section provides a summary of the results of applying this updated pricing methodology.

2.1. Average price movements

Our prices increase by an average of 8.2% on 1 April 2026. The average aggregate change for each connection category is:

Connection category	Average change %
General	8.7%
Irrigation	5.7%
Industrial	11.5%
Large Users	23.4%
Generation	1.1%
Streetlighting	9.6%
Overall	**8.2%**

2.2. Drivers of price movements

Key factors affecting our price movements for the FY27 update include:

- Our regulated price path which was reset by the Commerce Commission with a step increase for FY26, and annual increments of around 13% reflecting a return to normal levels of capital costs, and providing a catch-up on the inflationary pressures experienced during the previous 5-year regulatory period.
- Transpower's 20% increase in charges to us as it follows its own regulated price path the Commerce Commission set out.
- Within the limit provided by our price path, our forecast administration costs are reducing as we roll out of a year that included an allowance for one-off system replacement expenses, and this is offset by an increase in our operating and maintenance costs to align with expenditure committed in our asset management plan.
- Voluntary under-charging, where we set prices below the regulatory cap to mitigate impact on customers and provide a stable price path.

Together, these changes combine to an 8.0% increase in costs, and with forecast movement in our chargeable quantities (some increasing, others decreasing), we have set an average price increase of 8.2% to meet our revised revenue target.

Item	Approximate impact on total delivery revenue	
	Percentage	$000
Our management costs	+0.2%	+100.3
Our asset costs	+2.5%	+1,576.1
Transpower's charges	+4.1%	+2,536.6
Payments to generators	+0.02%	+13.5
Regulated wash-ups, incentives, and limits	+8.5%	+5,324.1
Voluntary under-charging	-7.3%	-4,574.4
Total	**+8.0%**	**+4,976.2**

2.3. Customer impacts

In addition to the overall price movements above, we are continuing our path of pricing reform by adjusting the structure and focus of some of our pricing. We must also respond to align with new regulations requiring that we apply time-varying tariffs and provide credits for export in certain circumstances. These changes have an additional impact on customers. Any pricing reform creates winners and losers, and we are conscious of the impact on customers which comes on top of the underlying price increase. The main changes are:

Change	Categories affected	Impact
Transitioning from volume to fixed prices	General 8kVA, 20kVA and 50kVA	For the General Supply 20kVA connection category we are following the industry phase out of the low fixed charge regulations, increasing the fixed daily charge from 75c/day to 90c/day. This step-change allows us to apply a lower increase to our volume-based prices that apply across the General Supply category. 8kVA and 50kVA categories have a corresponding adjustment. On its own, this change means that customers with lower-than-average usage will pay more, and customers with higher-than-average usage will pay less. In general, this also means that commercial customers will pay less and residential customers (who tend to be lower users than commercial customers with the same capacity) will pay more. Further, it reduces the savings available for customers that elect to invest in alternative energy sources (gas or solid fuel heating, solar generation), and reduces the savings associated with installing efficient heating appliances, insulation and lighting.
Introduce export credits	General 8kVA, 20kVA and 50kVA	We will provide credits to electricity retailers where customers inject surplus generation to our network that helps offset peaks. In the urban Ashburton area, the credits will apply on winter evenings, and in those rural areas where load is the main driver of our costs, the credits will apply on summer afternoons.
Price volumes using Day/ Night and Weekend tariffs	General 8kVA, 20kVA and 50kVA	We will apply time-based tariffs instead of anytime pricing where metering allows. Controlled tariff options will remain with a low flat price (and are already time-varying on the basis that they effectively attract a nil price at times when they are switched off).
Recast volume pricing for larger commercial supplies	General 69 kVA to 300 kVA	We are decoupling our volume pricing for larger general subcategories, reducing volume pricing and instead applying higher capacity charges to better reflect our cost drivers.
Introduce an average demand charge	Irrigation and Industrial	We are introducing an average demand charge to better reflect cost drivers, with the new charge based on half-hour metered demand and expressed as $/kW/day.
Introduce a volume price for streetlighting	Streetlighting	To more transparently recognise our cost savings through conversion to energy efficient lighting, we are converting a portion of our charge for streetlighting into a volume-based component.
Introduce recovery charge for the industrial category	Industrial	We are introducing a separate price category to ensure that we collect our target annual revenue when an industrial customer undertakes seasonal disconnection (or otherwise disconnects to avoid charges).

2.4. Future price movement expectations

Our pricing strategy sets out a basis for future pricing reform. Over the next five years, we expect:

- Capacity based fixed charges for general connections will increase further. The phase-out of the low fixed charge regulations will be completed on 1 April 2027, and we will look to align volume price with volume driven costs (which are somewhat limited), with a shift toward capacity and peak demand-based charges.
- Peak related time-of-use volume charges may become more targeted in terms of timing and location.
- Irrigation customers will see lower price increases relative to other categories as we progressively adopt the volume-based pricing approach in our cost allocation to match the approach that Transpower uses under the TPM.
- Further bespoke pricing will be developed to accommodate the changing needs and supply security requirements as our industrial customers and grid-scale generators evolve.

Alongside this, we expect our future annual pricing reviews will result in further increases. The Commerce Commission's regulated price path provides for consecutive annual increases of 11% plus inflation over the next three years, as it progressively aligns with the revised cost allowances.

The amount Transpower charges us is also on a regulated path, where we expect increases in line with inflation over the next few years.

Combined, and allowing for the deferred increase within the current update, we expect our prices to increase by 8% to 9% over the next four years (under current settings). Following that, when we move into the next DPP reset, our preliminary expectation is that we expect our prices will remain flat or reduce.

2.5. Discounts

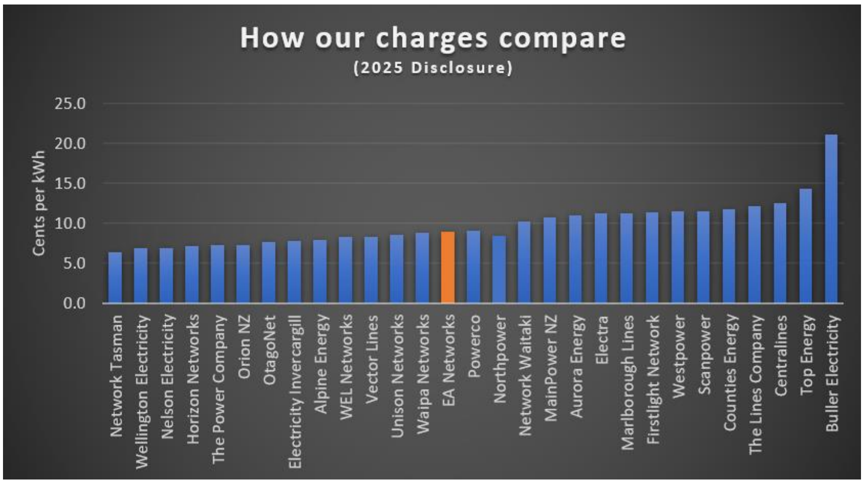
While it does not factor in this pricing methodology, in FY26 we allocated a $5 million (plus GST) customer discount by way of a credit to customers' power accounts in proportion to the distribution charges applied for their connection (up from $3 million the year prior).

In future we plan to continue applying discounts, returning a portion of the revenue collected through our pricing methodology.

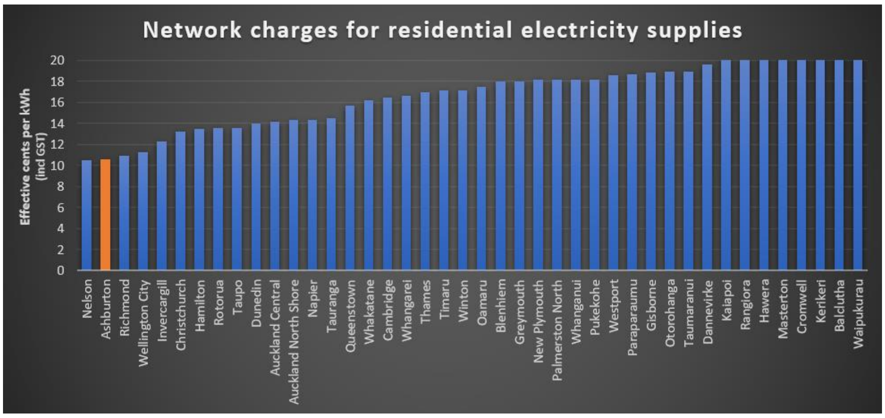
Our discount approach ensures that these funds remain in the local community. While a price reduction might provide a similar outcome for our financial accounts, it is less clear that a reduction would be passed on in lower retail electricity prices. Our discount approach ensures that our customers benefit from our sustainable profit objective.

2.6. How our prices compare

We are pleased that our community ownership and focus allows us to keep our prices low, and to return an annual discount. Based on the latest available disclosure information (prior to the price revisions set out in this methodology), our prices average 8.9 c/kWh for the combined transmission and distribution service, and this remains below the national weighted average of 9.9 c/kWh.



A separate comparison focusing on residential customers is available via the Ministry of Business, Innovation & Employment (MBIE) survey of domestic electricity prices. The latest survey shows that, for this category of customers, we provide one of the lowest pre-discount price averages.



3. Background

There are four key market segments to the electricity industry: generation, transmission, distribution and retail.

EA Networks is responsible for distribution within the Mid Canterbury region. Transpower is responsible for the national grid (transmission) and the majority of this service is charged to distribution companies, including us.

We set prices to cover our costs (including transmission costs), and charge electricity retailers for this service. Retailers, in turn, include our charges in their retail pricing plans that they make available to customers.

Importantly, we don't buy and sell the electricity, we simply deliver it. Electricity retailers purchase the electricity from generators via a wholesale market and contract with us to deliver it to their customers.

Our contracts with retailers (called the Default Distributor Agreement, or DDA) are all the same, and we apply the same prices regardless of which retailer a customer elects to sign up with. The aim is to provide a "level playing field" on which retailers can compete. Retailers are free to repackage and re-bundle our charges (together with all their other costs) as they see fit.

This document sets out how we establish, structure, and set the prices for this delivery service. Prices and price structures that customers see in their retail power accounts may look quite different to the prices and structures we establish.

4. Pricing considerations and objectives

A wide range of factors and objectives influence our pricing, in terms of the amount we charge, how we share cost between different customers and customer groups, and how we structure our pricing.

This section sets out the factors influencing our pricing and pricing reform.

4.1. Pricing strategy

Our purpose is:

> *"Enabling our region"*

To support this purpose, our pricing strategy is:

> *"Reform prices to support growth, provide affordable and equitable services, enable technical innovation and facilitate sustainable production."*

We last revised our pricing strategy in 2025 to include our refreshed purpose statement, with a headline focus on enabling our region. Encouraging efficient use of our network and enabling decarbonisation remain as corner-stone aspects of our strategy in support of this overall goal.

Our pricing reform roadmap in section 5 sets out the key stages of our pricing strategy.

4.2. Economic factors

We structure our pricing with the aim of providing economically efficient incentives. When faced with prices that reflect our costs, customers will make efficient decisions when deciding between an electrical solution (using our network) or an alternative. They will also make efficient decisions about where they locate that solution, and the time of day that they elect to use electricity.

Over time, the efficient decisions of customers will drive an appropriate level of investment in our network.

Providing economically efficient incentives requires a balance between setting prices that reflect our complex and dynamic shared costs, and other economic factors, including:

- Simplicity – for customers to respond, they must understand the pricing, and understand the actions that lead to higher costs or savings.
- Stability – many of the decisions customers make apply for long durations (for example, installing a heat pump). We need to provide customers with confidence that our pricing will not undermine their decision further down the track. In economic terms, customers' short-term reaction to pricing is inelastic.
- Transparency – customers need to be able to see what contributes to our charges so that outcomes are anticipated or expected.
- Transaction costs – the costs of maintaining more complex pricing offsets the efficiency benefits. Electricity retailers may elect not to pass through structures that drive high costs into their retail operations.

- Standardisation – while individual distributors face locational specific cost drivers, most electricity retailers operate nationally. Our pricing structures will only influence efficient customer decisions if they are reflected in retail pricing plans, and structures that align across distributors are more readily adopted.

4.3. Sustainability and decarbonisation

As part of our commitment to the wellbeing of our community, we have a significant role to play in moving to a sustainable future to improve social, economic, and environmental wellbeing. A key aspect of this journey is decarbonisation. Unlike many other countries, New Zealand is in a good position to decarbonise through electrification. The Climate Change Commission and Ministry for Environment have identified that electrification of transport provides the greatest opportunity and least cost means for our community to decarbonise. Alongside this, electrification of process heat (for example, replacing coal boilers with electric heating) will provide substantial carbon emission reductions.

We aim to structure prices to avoid barriers and promote the uptake of decarbonising technology, including:

- providing stable pricing against which customers can reliably make decisions,
- providing attractive off-peak charging options for electric vehicle charging,
- transitioning away from volume pricing as it:
    - discourages electrification,
    - promotes 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).

Electrification will require additional generation, and it's important that this generation is both renewable and low cost. For our area, we have identified that large scale solar generation currently provides the most economical solution, and we ensure that our pricing supports these generation developments.

4.4. Customer preferences

We recognise that customers are at the heart of our service, and their preferences are an important factor in our pricing development. Through our surveys, focus groups, and interactions with customers, feedback from electricity retailers and the experiences of other distribution companies, we have learnt that:

- Customers prefer simple price structures,
- Customers want to see any change in consumption reflected in their charges without delay,
- Customers do not want to be charged based on historic usage levels, or usage of prior customers that might have been at the property,
- Customers do not like seasonal pricing, they see it as a penalty at a time when they want to use more electricity (and this feedback even extends to customers that benefit from seasonal pricing),

- Customers view peak pricing as a penalty, rather than an incentive to use electricity at off-peak times,
- Customers prefer usage-based charges over fixed (unavoidable) charges (which is the opposite of the preference we observe in mobile phone and internet connection pricing),
- Customers, in general, do not want to engage in real time responses. They prefer stable options that reward regular patterns of behaviour, or responses that are automated (recognising that there are some exceptions to this preference),
- Customers want pricing options, so they can select plans that meet their needs and minimise charges, and
- Customers continue to be supportive of the current level of prices, with a majority of those surveyed not willing to pay higher prices to reduce the potential for outages, or to reduce time without power.

Several of these preferences conflict with other pricing considerations, and we must find a balance between the objectives when developing pricing.

Customer consultation

We survey our customers seeking feedback and preferences every two years, with the latest survey completed in December 2025. For this survey we employed an independent specialist survey firm to construct an electronic survey and we sought feedback from all customers where we hold a current email address. We approached a total of 17,700 customers (93% of all customers), and we received a response from 1,361 customers.

The survey covers pricing and consumer expectations regarding outages and quality of supply (and how these relate to price), as well as a range of questions to gauge our service delivery performance.

This latest survey informs and supports the customer preferences listed above. Key messages received were:

DATA INSIGHT: A high proportion of Respondents report making changes to electricity usage in response to costs.

A small majority of respondents (62%) believed that remote consumers should pay more for power than other consumers due to the increased cost of supplying power connections to those areas.

"Being very careful of lights, heating and all electrical usage and minimizing as much as possible."

DATA INSIGHT: Respondents are highly aware of how much electricity they use and are taking multiple steps to minimise usage. High electricity costs are of great concern and driving many of these changes.

"Already a low user. Any further changes may affect quality of life."

"The team we dealt with were awesome, the price was fantastic compared to other quotes, and the work was completed well within time."

Shareholders' committee

The company structure lends itself to direct feedback from customers. EA Networks is a co-operative company, our end user customers are also (generally) our shareholders. A Shareholders' Committee has been established and has operated since the co-operative was set up. This committee of seven represents all consumer shareholders and is focussed on ensuring that consumer views are prioritised. The committee takes an active role in providing feedback to our board and management regarding customer expectations on price changes and related matters.

Ashburton District Council

Our single largest shareholder is the local District Council. This entity is also one of our largest connected customers. We seek and receive regular direct feedback in relation to pricing from the District Council. The Ashburton District Council also elect three of the seven member Shareholders' Committee.

Locals on Board of Directors

EA Networks also ensures that there is a local focus to the make-up of our Board of Directors. This ensures that local views are always considered when making business decisions, including pricing.

Customer interaction

We listen. Every day we interact with our customers in relation to new connections, upgrades, and downgrades. When customers express views to us directly or via social media, we engage, and we share the views internally. We also receive regular feedback from retailers relating to customers' preferences.

From these combined sources we are comfortable that we are considering the views of both individual customers and the wider market from a macro perspective, especially where that relates to pricing.

4.5. Equity

We are conscious that our pricing can create winners and losers (in economic terms, wealth transfers).

We operate a shared network, and it's important that all customer groups benefit from the presence of other customer groups – in other words, all customers should contribute to common costs. And taking a step further, all customers should contribute a *fair* amount toward common costs.

All customers should share in the benefits of greater utilisation and the costs of upgrades when they are required. We aim to avoid an incremental cost approach for new customers as this leads to very low (or no) charges for lucky customers when surplus capacity is available, and very high charges for customers that happen to connect when an upgrade is required.

We tend to avoid locational pricing, as we usually elect where to put our network. Locational pricing would benefit lucky customers that are close, but penalise unlucky customers that are further away from where we elect to put assets. Broadly speaking, all our customers are effectively the same distance from the Waitaki Valley (the source of most of our electricity).

We aim to reflect the long-term costs of our assets in our prices to promote generational equity. We avoid charging higher prices for newer assets that have a higher capital value, and we instead reflect the fact that the service is provided over the life of the asset. In practice, this means that we average accumulated depreciation when allocating assets to customers and connection categories.

4.6. Vulnerable customers

We recognise that we have vulnerable customers in our community. Vulnerable customers are those that do not have the resources to accommodate additional costs, nor to adapt their usage to mitigate the additional cost. A subset of vulnerable customers is those who are in energy hardship – these customers are relatively high users who are spending a disproportionate amount of their income on energy.

While we might adjust our pricing structure to provide efficient incentives, these changes will affect all customers, including those that are unable to respond, and may not be contributing to the behaviour that we are looking to influence.

We are transitioning away from volume-based charges to improve the efficient use of our network in the long term. However, we know that many of our vulnerable customers are low users, and for these customers, the transition will mean they pay more as the volume-based prices (which they largely avoid) diminish, and fixed charges (which they can't avoid) ramp up.

To mitigate this we:

- Stage the transition over a number of years, providing more opportunity for vulnerable customers to adapt and for support mechanisms to adjust.
- Look to provide new capacity options that reflect the reduced use on our network through lower fixed charges.
- Provide targeted relief to customers in need, support energy advocacy and energy efficiency services, and partner with community agencies to educate and support our community on how to lower their power bills.

Our energy advocacy work includes:

Home Insulation
- *In partnership with Community Energy Action*
- *Part of Warmer Kiwi Homes Govt Initiative*
- *From 1 April 2025 have supported 205 homes to have ceiling and / or underfloor insulation provided*

Community Wellness Fund
- *Community agencies can apply to support their clients / community*
- *Focus on improving energy efficiency / wellness*
- *First year trialling this – two agencies on board*

Community Engagement
- *A&P Shows, local fairs, wellbeing / cultural days*
- *In-home and small group energy efficiency education*
- *Free supply of products including LED bulbs, v-seal, draught stops*
- *Supported by Connecting Mid Canterbury*

4.7. Regulation

A range of regulatory obligations influence our pricing. Some of these regulations are "hard regulation" which set out obligations that we are required to meet, and other parts are "soft regulation" which sets out purpose and intent. The soft regulation often clashes with other considerations or location specific issues, and we must balance the extent to which we align.

The following sub-sections set out the main regulatory influences on our pricing.

Commerce Commission

The Commerce Commission administers and enforces Part 4 of the Commerce Act which sets out a range of regulation applicable to Electricity Distribution Businesses (EDBs). In relation to pricing, under the Act, the Commission has put in place disclosure requirements and price regulation.

Disclosure requirements

The disclosure requirements require us to publish a wide range of information. In relation to pricing, this includes this pricing methodology document, schedules of prices, notification of price changes, information about any non-standard contracts, details about prices and payments for distributed generation, and details about our capital contribution policy (for new connections or upgrades). It also requires that we document our alignment (or otherwise) with the distribution pricing principles published by the Electricity Authority (see below).

Price regulation

The price regulation that applies to EA Networks is the Default Price Path (DPP). This sets out the total maximum allowable revenue for our service, which includes a range of incentives and adjustments based on performance, as well as wash-ups for any prior under or over recovery.

Importantly, the regulation only caps the total revenue we can recover through prices. It does not set limits for any individual customers or connection categories.

While this pricing methodology takes a "building blocks" approach to pricing (adding up all our costs), we must then apply an adjustment to ensure that we meet the limit set by the DPP to ensure that prices comply with the maximum revenue cap.

Electricity Authority

The Electricity Authority is established under the Electricity Industry Act 2010, and its purpose is to regulate the electricity industry in New Zealand. Under the act the objective of the Authority is *"to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers".* Pursuant to its objective, the Authority has established the Electricity Industry Participation Code (the Code). It also sets distribution pricing principles and a range of guidelines.

We understand that a key concern driving the Authority's work program in relation to distribution pricing is to ensure that New Zealand's transition to a low emissions economy is on the lowest cost path. The Authority has identified distribution pricing is one of the core elements of this efficient transition, as the system seeks to accommodate increased distributed energy resources, demand response, and electrification of transport.

The Authority's current interest in distribution pricing reform piqued in 2019 when it identified that New Zealand might make an inefficient investment in solar panels. In a consultation paper titled "More efficient distribution prices", it made the claim:

> Without distribution price reform, consumers have an incentive to over-invest in solar panels, because these reduce the total kWh they draw from the network – but not at peak times. This effect is real and large. The expected cost of this overinvestment is estimated to be $2.7−5 billion over 25 years.[5]

Many of the changes we are making in response to the Authority's regulation are to reduce or remove distortionary influences, and this will reduce the incentive for things like solar generation, and for customers that have already invested in solar generation, it will reduce the extent to which they can offset electricity costs.

The rest of this section highlights the main areas where the Authority's regulation influences pricing.

Pricing principles

The Authority maintains a set of pricing principles. These are not a regulation in themselves, but regulation under the Commerce Act requires us to declare and explain our alignment (or otherwise) with these pricing principles. The current distribution pricing principles are:

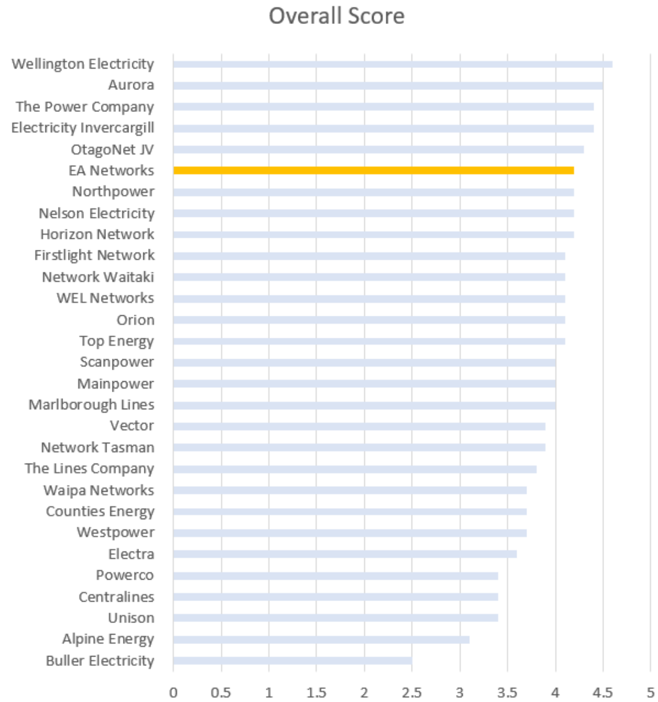
> (a) Prices are to signal the economic costs of service provision, including by:
>
> (i) being subsidy free (equal to or greater than avoidable costs, and less than or equal to standalone costs);
>
> (ii) reflecting the impacts of network use on economic costs;
>
> (iii) reflecting differences in network service provided to (or by) consumers; and
>
> (iv) encouraging efficient network alternatives.
>
> (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.
>
> (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.
>
> (d) Development of prices should be transparent and have regard to transaction costs, consumer impacts, and uptake incentives

The Authority has reinforced the pricing principles through several formal communications that we have taken account of in this methodology. These include:

- A consultation paper on distribution pricing reform – dated 4 January 2019, which included a specific concern around consumers investing in solar panels. It included the warning:

  > In 2015, NZIER estimated that just in relation to solar panels alone distribution charges could increase by up to 30 per cent over 10 years. This would add 10 per cent to the retail bills of consumers without solar panels.[1] They effectively end up cross-subsidising others to over-invest in solar panels. The economic cost of this outcome occurring has been estimated to be in billions of dollars.[2]

- A letter to distributors – dated 20 November 2020 expressing concern that pricing reform has slowed, suggesting that efficiency has worsened and highlighting the impact this has on accelerating distributed energy resources and electric vehicle uptake.
- A distribution pricing practice note – a document that provides expectations, examples, and detailed explanation of what each phrase in the pricing principles means. It also includes guidance on the pass-through of transmission charges.
- Distribution pricing scorecards – the Authority has reviewed and ranked distributors' prices against a set of criteria and has released a one-page summary for each distributor. The latest scorecard assessments are available at https://www.ea.govt.nz/industry/distribution/distribution-pricing/. The Authority scored EA Networks 4.2 out of 5 in this assessment (for pricing applying until 31 March 2023), which places us 6th best (in equal position with 4 others).



The scorecard identifies several areas where we can improve our alignment with the pricing principles.

- A letter to all distributors – dated 6 May 2022, highlighting three main focus areas:
  - assessing and addressing pricing issues, such as first mover disadvantage, for new and expanded connections,
  - pass-through of new transmission pricing to distribution pricing,
  - progressing analysis of possible regulatory options to drive faster reform.

  The letter also called for locational pricing, clarifying the Authority's view of related regulations, and noting that locational pricing is consistent with its pricing principles.
- An open letter to all distributors – dated 19 September 2022, setting out expectations for faster reform highlighting five areas of focus:

  - responding to future congestion,
  - addressing first mover disadvantage,
  - alignment with the Authority's guidance on passing through transmission charges,
  - the phase-out of low fixed charges,
  - avoiding or transitioning away from use-based charges such as anytime maximum demand charges.

- A letter to all distributors – dated 16 December 2022, indicating its intention to change the focus of scorecard assessments to increase the weighting of the efficiency measure, introduce a measure of progress against roadmaps and progress against its focus areas.
- Development of targeted reform of distribution pricing – in July 2023, the Authority initiated a programme of targeted reform with an issues paper setting out intended areas for interventions:
  - Pricing that signals the cost of using the network at certain times of high demand
  - Pricing that does not distort the use of the network during off-peak periods
  - Efficient allocation of shared costs between consumer groups
  - Connection pricing that is both efficient and consistent
  - Retailer response to distribution pricing signals.
- A "Next Steps" paper dated 7 May 2024 setting out an intention to regulate connection pricing, refining guidance on peak and off-peak price signalling, and monitoring the uptake of time-of-use tariffs.
- An open letter to all distributors – dated 24 May 2024 setting out five new additional areas of focus:
  - Allocate revenue transparently (we don't actually allocate revenue, we allocate costs)
  - Assign all ICPs to time-varying distribution tariffs with limited exceptions
  - Set peak rates based on a measure of long run marginal cost
  - Reduce off-peak and controlled rates
  - Follow up on asset management plan reporting on readiness for increased electrification
- An open letter to all distributors – dated 31 January 2025 reinforcing guidelines for communicating price charges to customers:
  - Provide timely, transparent and reliable communication
  - Demonstrate empathy and proactive support in communications
  - Be accurate and consistent in public statements

Regulation

Building on the incentives above, the Authority is also requiring pricing reform via amendments to the Code:

- Code amendments, effective 1 April 2026 and 1 July 2026, requiring:
    - That we must apply charges based on information provided by retailers (which appears to exclude the option to apply charges based on information that we hold and maintain, such as the capacity of supply),
    - Where we offer time-varying pricing, we may only charge a customer using time-varying pricing (we don't charge customers, and some customers have multiple power supplies which include supplies that are not suitable for time varying pricing),
    - That we provide payments for injection for price categories that target residential or small business customers, where such payments are time and location based and linked to the long run marginal costs of peak demand (on average and over time) that injection can avoid.

Pricing principles for distributed generation

Contained in part 6 of the Code, the main aspect of this is that generation must only attract the incremental cost of connection and is able to utilise existing capacity (funded by others) free-of-charge. It is unclear what should occur where a customer utilises connection assets for both load and generation, or if the order of connecting either load or generation might influence the outcome.

This approach supports our sustainability objectives (promoting connection of renewable generation) but is at odds with our equity objectives. It also creates a significant barrier when an upgrade is required, and the single generating customer that causes the need for that upgrade is burdened with the entire cost of the upgrade.

We also must be careful not to plan ahead for future uptake, because if we allow for extra hosting capacity when undertaking upgrades, that surplus capacity becomes "existing" capacity that we must then allow new generators to use free-of-charge.

Our network has been built for, funded by, and is owned by our customers. While it was put in place to meet load requirements, it also has the ability to host renewable generation. Our customers are now finding that they can't inject their surplus generation because we have been required to give the available generation hosting capacity to external parties that have established grid-scale solar farms.

As a separate initiative, the Authority has now implemented Code amendments requiring us to provide credits for customers that generate and inject during periods of peak demand. The credits must reflect the marginal costs of peak demand (on average and over time) that injection can avoid. Our basis and methodology for establishing these credits is set out in section 7.2 below.

Guidelines for pass-through of transmission charges

The Authority has included guidance on the pass-through of transmission charges within the distribution pricing practice note. We consider the guidance is not entirely workable for our situation in some respects. For example:

- The guidance calls for fixed charge structures, whereas the residual charge (for us, the vast majority of our transmission charge) is applied on a volume basis. The Authority's approach would place the burden or benefit of one customer's actions on others.
- The guidance says we should phase in and then phase out the lagged residual charge for large customers. Continuing a phase out of charges after a customer disconnects is difficult, and the Authority suggests we address this with a contractual arrangement. However, the mandated default distributor agreement, under which the Authority requires that we provide our service, includes a core term that prevents us applying charges once a customer disconnects.
- The guidance suggests we should use fixed charges, but we should also mimic the TPM for benefit-based charges. Most benefit-based charges are applied to us on the basis of the extent to which our customers benefit in terms of lower energy prices. To reflect this, we would need to allocate it between customer categories based on usage. If we then apply a fixed charge structure to recover the allocation we would create cross-subsidies (a customer's increasing usage would attract a higher allocation for the category, but they wouldn't pay more).

The guidance describes Transpower's charges to us as being "fixed-like", yet we observe that the charges use a volume-based allocation, and are not fixed.

The guidance calls for lagged quantities to be used (and this was later extended to "lagged and averaged" in one of the Authority's letters). As noted in section 7.7, this approach is not a workable solution for our electricity retailers and customers and so we have elected to take an alternate approach from the guidance.

Consult with retailers on price changes

Part 12 of the Code requires distributors to consult with retailers on any material change in price structure. We undertake this consultation but we receive very little feedback, and often that feedback relates to the impact on the retailer, rather than the impact on their customers.

Regardless, we are cognisant of the transaction cost for retailers and that any risks our pricing might inherently expose them to will be reflected in retail prices.

We partner with retailers to provide a delivered electricity service and we seek pricing solutions that will provide a seamless experience for customers

Guidelines for communications about price changes

The Authority has published guidelines indicating how price changes should be communicated.

Standardised file formats

The Authority has regulated a range of standard file formats, including a file format which is intended to convey pricing information between distributors and electricity retailers.

Ministry of Business, Innovation and Employment (MBIE)

Low fixed charge regulations

MBIE administers the "Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004". The regulations require us to provide a tariff option with a low fixed charge for residential customers. As well as having a low daily fixed charge, the option must:

- have only one fixed charge,
- in addition to that fixed charge, only have variable (volume-based) charges,
- variable charges must not be tiered or stepped according to the amount of electricity consumed,
- the price for the variable charge must be limited so that an average consumer using 9,000 kWh per year would pay no more using the low fixed charge option, and
- for every price option that we make available for residential customers, we must make a matching low fixed charge option available.

We have an exemption from the regulations for residential customers with a capacity greater than 15 kVA.

The low fixed charge regulations are being phased out over a 5 year period, with the maximum daily charge limit (for distributors) being increased by 15c/day each year. For FY27, the limit is 90c/day. During the phase out period, all the restrictions noted above remain in place.

Electricity Price Review

MBIE commissioned an "Electricity Price Review" (Hikohiko Te Uira) for the Government in May 2019. Its report included 32 short, medium and long term recommendations, and it subsequently set up a dashboard to monitor progress against the recommendations. Three of these recommendations relate to electricity distribution pricing:

- Issue a government policy statement on distribution pricing – A key aspect of the recommendation is that the policy statement should require that costs be allocated between household and business consumers in a way that is fair and efficient. The Government subsequently issued a policy statement in 2024 (see below).
- Ensure distributors have access to smart meter data on reasonable terms – The Electricity Authority implemented a default data access agreement. Unfortunately, the default makes it difficult for us to use the data in any meaningful way as it restricts access to the data to staff that only work in the regulated distribution service (all our staff participate in activities beyond this limited scope). We are making progress with retailers to obtain data together with permission for access by specified staff, and we expect to be able to use a more granular approach in our future price setting.
- Phase out low fixed charge tariff regulations – MBIE subsequently amended the low fixed charge regulations to phase out the requirements over a five-year period (see above). During the phase-out period we are able to increase fixed charges but a number of other restrictions remain in place.

Government policy statement

In October 2024, the Government issued a Statement of Government Policy (GPS) to the Electricity Authority setting out its expectations for the industry.

The GPS centres on *"reliable electricity at lowest possible cost to consumers ... including through the provision of sufficient electricity infrastructure to ensure security of supply and avoid excessive prices."*

In relation to our activities, the GPS states:

> **"Strengthen transmission and distribution networks**
>
> Electrification of the economy will require significant investment in strengthening transmission and distribution networks. It is critical that this investment is economically efficient, which means (among other things) that it reflects demand and optimises new capacity in a manner that avoids unnecessary cost increases for consumers, while ensuring network reliability.
>
> Efficient network pricing is essential:
>
> a) To find the lowest cost solution, which may include demand-side response and flexibility to avoid or defer the need for network capacity augmentation; and
>
> b) For connections to enable efficient investment in new electricity consumption, including electrifying transport and process heat in industry."

5. Pricing reform roadmap

Our pricing strategy is:

"Reform prices to support growth, provide affordable and equitable services, enable technical innovation and facilitate sustainable production."

Building on our previous strategy, we adopted this strategy for FY26 to provide a focus for our pricing reform. Our roadmap sets out the stages of our pricing strategy. We expect this to evolve over time to match the changing environment in which we operate. The steps reflect the considerations and objectives set out above.

Progress

While stability is one of our key considerations, our pricing is not static. We have been actively adjusting our structure and approach to align with the pricing considerations and objectives set out in the previous section. In particular, we have moved to better align with the Authority's pricing principles. This section sets out and records the changes we have applied in recent years along our road map of reform.

Activity	Description	Timing
Advocate in relation to external influences	Participate and advocate for our customers' interests in reform relating to: • the transmission pricing review, • removal of low fixed charge regulations.	Completed during FY20, FY21 and FY22

Implement transmission price changes	Revise our cost allocation and begin the transition to reflect the revised transmission charging approach, and pass through the significant increase in costs.	Completed during FY23
Fixed/variable rebalancing	Commence the rebalancing of fixed and variable charges, with the first increment in the increase of the fixed daily charge for the category applying to residential customers from 15c/day to 30c/day (accompanied by a 12% reduction in the main volume-based prices).	Completed and effective 1 April 2022
Support for vulnerable customers	We have activated our support mechanisms for vulnerable customers. We have increased our focus on energy advocacy, working with community agencies to provide in-home energy assessments for vulnerable customers, delivering low-cost energy solutions such as LED bulbs, draught stops and v-seal to help create more energy efficient homes. In 2024 we also recommenced targeted funding to support the Warmer Kiwi Homes initiative, working with Community Energy Action Charitable Trust to provide 100% funded insulation into homes that meet the Warmer Kiwi Homes criteria	Implemented during FY22 and ongoing
Rebuild our cost allocation model	Refresh our pricing model to: • Adjust our pricing categories to better reflect current attributes • Take a more granular approach to our cost allocation between subcategories within the general category • Take account of the new transmission pricing methodology	Completed during FY23
Reconsider the cost reflectiveness of our current pricing structures	Review price components to: • consider the extent to which each component reflects costs, influences customer behaviour, and meets the pricing objectives, and • identify pricing component alternatives.	Completed during FY23
Revise industrial category charges	We revised the industrial category charges to be based on booked capacity – the level of network capacity that we reserve for their usage. The previous approach was to charge for the maximum demand level reached in each month – this led to customers with seasonal load paying much less than customers with a year-round load despite the level of assets employed being the same. The booked capacity approach also encourages customers to “right-size” their connection, helping address situations where new connections are over-sized or customers retain unused surplus capacity.	Implemented 1 April 2023, with a phase in period for adversely affected customers Completed FY26
Fixed/variable rebalancing	We continued with the rebalancing of fixed and variable charges, incrementing the fixed daily charge for the category applying to residential customers from 30c/day to 45c/day. This met almost all the additional revenue requirement needed to meet increased transmission and other costs through this increase (and there is consequently no reduction to apply in volume prices).	Completed and effective 1 April 2023
Low fixed charge exemption	With the shift away from volume pricing, to ensure that large capacity residential connections continue to pay an appropriate share, we have refined the boundaries for our General Supply subcategories and will apply higher fixed charges for larger capacity connections. To ensure ongoing compliance with the low fixed charge regulations, we applied for and were granted an exemption from offering low fixed charges for 3 phase and greater-than 15 kVA supplies.	Completed November 2022

Provide a low capacity category	With the increased fixed charges, to continue to reflect the lesser extent to which low capacity (low volume) customers use our network, we have opened up an 8 kVA category for low capacity residential supplies. The category is available for residential connections with a capacity up to 32 amps (about half the normal residential capacity) and is aimed at single bedroom units (and similar). The category has a lower fixed charge (and standard volume prices). Combined with the exemption noted above, our residential customers are now spread over three capacity categories which allows us to more accurately reflect the relative impact on cost that the different size connections drive.	Completed and available 1 April 2023
Provide a day vs Night and Weekend volume pricing option	Anticipating an increase in electric vehicle charging, and signalling the cost that this would impose if it was added to evening peak loads, we initiated an optional time-of-use (TOU) pricing option. This provides an incentive for customers to shift discretionary load into the nights and weekends (away from our peaks).	Completed and available 1 April 2023
Fixed/variable rebalancing	We have continued with the rebalancing of fixed and variable charges, incrementing the fixed daily charge for the category applying to residential customers from 45c/day to 60c/day. This change exceeded the additional revenue requirement needed from the category, and we are able to reduce the headline volume price by 2.5%.	Completed and effective from 1 April 2024
Enhance our low capacity category	Recognising the impact that higher fixed charges have on low users, we enhanced the savings available with our low capacity 8kVA category (about half the capacity of a normal residential supply). For these connections the fixed charge was adjusted to 30c/day (half the fixed charge applied for the standard category).	Completed and effective from 1 April 2024
Split our 150kVA category	The previous G150 category catered for a very wide range of capacities. To an extent, the different levels of usage were reflected through volume pricing – high use customers naturally paid more. To preserve this distinction as we move away from volume pricing, we are splitting the category into two, and applying a higher fixed daily charge for those with a higher capacity supply.	Completed and effective from 1 April 2024
Provide option for EV super chargers connecting to our high voltage network	New technology is utilising our network differently. To better reflect the more limited set of assets used by small but high voltage connections (such as EV super chargers), we have added an industrial subcategory that provides a lower price.	Completed and effective from 1 April 2024
Use smart meter data to provide more equitable irrigation charges	To equitably accommodate the new and more diverse loads occurring at irrigation connections (rig drives, booster pumps, air conditioning, SCADA and communications equipment), a metered assessment was added to the assessment of chargeable demand. Irrigation sites with additional equipment will pay proportionally more for the electrical demand of this equipment, and this will lower the overall price required to meet the revenue requirement for the category (providing a benefit to others in the category).	Completed and effective from 1 April 2024
Fixed/variable rebalancing	We continued with the rebalancing of fixed and variable charges, incrementing the fixed daily charge for the category applying to residential customers from 60c/day to 75c/day. This represents a 25% increase in the fixed daily charge and allowed us to apply a lower 20.7% increase in the volume component of prices to match the revenue requirement for the category.	Completed and effective from 1 April 2025
Fixed/variable rebalancing	The ongoing shift toward fixed and capacity based charges supports the equity of our pricing, as charges better reflect the cost drivers of our service. We completed work to determine the endpoint for this rebalancing in advance of the restrictions being lifted. If implemented for FY26, the target	Completed prior to 1 April 2026

	price for our main residential category would have been $1.55 per day, approximately double the (then) current limit of 75c/day.	
Split the general 100kVA category into two	As we shift our pricing to focus more on capacity charges, the categorisation of power supplies becomes more important. We expect customers and their electricians to "right-size" electrical supplies, and upgrade/downgrade capacities as customer needs change. To facilitate this efficient behaviour, we have enhanced the categories that are available to select from. In FY26 we split our 100kVA category into two by creating a new 69 kVA category. This eased the price impact as customers transition between the categories and allows us to better reflect costs over a smaller averaging range.	Completed and effective from 1 April 2025
Introduce an irrigation recovery charge	We observe a small number of customers seasonally disconnecting, apparently in order to avoid charges. Network capacity must continue to be reserved and our costs continue through the period of disconnection, but these costs inequitably fall to other customers. To address the issue and prevent wider application of the behaviour, we introduced an irrigation recovery charge. When an irrigator disconnects, the connection is shifted to a new recovery category that carries a higher price. On reconnection, that higher price then applies through until the missed charges have been recovered. This approach allows customers to seasonally disconnect if they choose to without a cost burden falling to others.	Completed and effective from 1 April 2025
Increase our focus on energy advocacy	Recognising that our changes and price increases have a disproportionate effect on some customer groups, we significantly increased our funding for targeted energy advocacy. This allowed us to target customers in need, including those experiencing energy hardship. Activities include energy efficiency assessments, education on using energy efficiency, encouraging selection of lowest cost retailers and pricing plans. For low capacity (eg single person) residential dwellings, we proactively promote our lower cost 8kVA price category, and advocate for retailers to provide a matching retail price option.	In place from 1 June 2025

Current year

This section sets out the roadmap stages and changes that we are implementing in the current year (FY27), and how these relate to our strategy. We acknowledge that some of these changes were not signalled in our previous methodology, and have been applied in response to regulated requirements that were not anticipated at the time our previous methodology was prepared.

Activity	Description	Timing
Fixed/variable rebalancing	We are following the regulated path to remove our low fixed charge for residential customers. For our general 20kVA price category, we are increasing the fixed daily charge from 75c/day to 90c/day and using the additional revenue to offset volume price increases. This is the final year where fixed charges are capped, and from 1 April 2027 the regulations are removed.	From 1 April 2026
Fixed/variable rebalancing	For our larger commercial general categories, we are breaking the link to volume prices set for the smaller categories, and instead recasting and advancing the balance between fixed and capacity charges. This provides for a step change in fixed capacity charges with an increase averaging 140%, which provides for a 24% reduction in volume prices. At the same time, it allows us to withdraw the rarely used controlled tariff options that were not targeted at these larger commercial customers.	From 1 April 2026

Introduce export credits	For our general 8kVA, 20kVA and 50kVA pricing categories, we will provide credits to electricity retailers where customers inject surplus generation to our network that helps offset peaks. In the urban Ashburton area, the credits will apply on winter evenings, and in rural areas where load is the main driver of our costs, the credits will apply on summer afternoons.	From 1 April 2026
Price volumes using Day/ Night and Weekend tariffs	For the 8kVA, 20kVA, and 50kVA categories, we will apply time-based tariffs instead of anytime pricing where metering allows. Controlled tariff options are already considered to be a time-based tariff as they effectively carry a nil price during times when they are turned off (and these options remain in place).	From 1 April 2026
Introduce an average demand charge	For irrigation and industrial customers, we are introducing an average demand charge to better reflect transmission cost drivers, with the new charge based on half-hour metered demand and expressed as $/kW/day. A small proportion of our costs are driven by consumption, and this component ensures that customers who increase their consumption bear the added costs. It also rewards customers that are able to reduce consumption through things like energy efficiency and renewable generation.	From 1 April 2026
Introduce a volume price for streetlighting	To more transparently recognise the cost savings (to us) through conversion to energy efficient lighting, we are converting a portion of our charge for streetlighting into a volume-based component.	From 1 April 2026
Introduce recovery charge for the industrial category	Aligning with the approach taken for irrigation, we are introducing a separate price category to ensure that we collect our target annual revenue when an industrial customer undertakes seasonal disconnection (or otherwise disconnects to avoid charges).	From 1 April 2026
Withdraw from daily peak load management	Our load management is scheduled as a service level against which we apply preferential tariff options. With electricity retailers actively undertaking regular and targeted management of water heating load, we are withdrawing our scheduled daily load management and reverting to seasonal peak load management (only managing load in response to seasonal peaks). We also intend to participate with Upper South Island distributors in a coordinated management approach to reduce energy costs. Note that this is a change to the service level and the pricing options remain available.	From 1 April 2026

Future plans

This section sets out the changes that we expect to implement over the following five years.

Activity	Description	Timing
Monitor the effectiveness of our TOU pricing plan	Our TOU pricing plan is now effectively mandatory for our smaller general categories. A key driver is to signal capacity constraints associated with electrification of transport (EV charging). We plan to monitor the response to the pricing plan, and adjust the price points where necessary to optimise the response.	FY27 and beyond
Refine transmission pricing structures	With the new TPM, the majority of our transmission charges will be adjusted in proportion to changes in energy volumes (consumption). We plan to progressively adjust our cost allocation and prices to reflect this influence to ensure that customers are appropriately rewarded or charged in relation to changes in consumption.	First step implemented in FY26, ongoing changes from FY27

Develop non-distortionary pricing options	We plan to continue to investigate and develop pricing options for our residual charges (the level of charges over and above any cost reflective pricing). The aim is to develop pricing options, or combinations of pricing options that do not incentivise uneconomic responses by customers.	FY27 and beyond

Impact on connection categories

For our General Supply category, we expect that the reform will lead to lower volume-based pricing and higher fixed daily charges, together with greater segmentation for fixed charges based on connection capacity. Separately, our time-varying volume pricing should lead to retail pricing plans that allow customers to benefit from adjusting behaviour and moving usage away from peak times.

Our capacity break-points for the general sub-categories have been clarified. The allocation of connections to sub-categories has varied over time and we are undertaking a programme of shifting connections to the correct category. We estimate that approximately 2,500 need to be corrected and in each case we provide to the affected customer an explanation, advance notice, and options to avoid or mitigate the impact.

For our irrigation category, our reform has shifted a small part of charges from a fixed basis to an average demand basis, as we move to align with the way that Transpower charges us. This will mean that less frequently used irrigators will pay less than the more frequently used irrigation (relative to what they pay now).

We are also applying our metered assessment which supplements our assessment of the rated capacity of equipment that is installed. We are increasing a significant number of chargeable capacities as a result, and this will provide a more equitable allocation of our costs, and drive prices that are lower than they would otherwise be.

For our industrial category, we expect to transition the smaller connections into the appropriate General Supply subcategory (for those that are smaller than the minimum size) to better reflect the cost allocation approach. We have also introduced a small average demand charge consistent with our changes for the irrigation category, and this will increase by a modest amount as we bring it in line with the relevant allocated costs.

Resourcing

We have structured our reform to phase in the implementation over a number of years in order to mitigate the impact on customers (including through reducing rate shock). This also allows us to accommodate the changes within our normal resourcing levels. However:

- we plan to bolster our communications function to assist with the additional customer interaction that the changes will drive,
- we have adjusted our inspectors' gamut to include providing on-the-ground guidance for customers considering capacity options (right-sizing their supply), and
- we have implemented systems to support capacity monitoring and tracking of corrections for our general, irrigation and industrial categories.

6. Overview of pricing methodology

Our charges represent the delivery costs of electricity – we contract with Transpower to deliver electricity across the national grid from generation points to our network, and we provide the local network to distribute electricity to each connection, and to redistribute electricity generated by customers within our network.

We refer to our service as "distribution" and Transpower's service as "transmission". We call the combined service "delivery", and we set delivery prices to recover the costs of the combined transmission and distribution service (as well as other recoverable costs).

In summary, our pricing approach is to:

- establish total costs that drive our target revenue requirement, including:
    - administration costs,
    - operations and maintenance costs,
    - payments for export from generation,
    - transmission costs,
    - asset depreciation, asset disposal losses, return on capital invested and tax,
    - regulatory incentives and adjustments,
    - regulated pass-through cost allowances,
    - our regulated revenue cap under default price path,
- establish connection categories to combine connections that have similar load characteristics, use specific sets of assets, or otherwise give rise to a similar set of costs,
- assess each connection category's use of network assets and assign the average depreciated value of assets to each connection category. This allocation reflects the asset-based costs associated with our service for each category,
- allocate costs to connection categories to establish target revenue:
    - allocate asset related costs (operations and maintenance, depreciation and return on capital, regulated allowances) to each connection category based on the asset value assigned to each category from the step above,
    - allocate non asset-based distribution costs (administration costs) to each connection category using metrics that reflect the extent to which categories use (and therefore benefit from) our service,
    - allocate transmission costs to each connection category based on our assessment of each category's contribution to our grid charges,
    - allocate an adjustment to each connection category to meet the regulated default price path cap, meet contractual obligations to large users with fixed price contracts, to apply any level of voluntary under-charging, and to smooth any price shocks relating to restructuring,

- establish pricing structures by:
    - first establishing pricing components that reflect costs (that is, a change in customer behaviour is rewarded or charged at a level which reflects the cost impact on the service that we provide),
    - then establish non-distortionary pricing components to recover the balance of our revenue requirement,
- finally, using the structures established above, and having regard for our pricing strategy, sustainability and decarbonisation goals, customer preferences, equity and fairness, vulnerable customers and regulatory considerations set out in section 4 above, we set prices against forecast chargeable quantities to achieve the target revenue for each category.

The following sections set out the results of these steps in the order noted.

7. Application of pricing methodology

This section sets out the steps and key metrics of our FY27 pricing methodology.

7.1. Target revenue for FY27

Our target revenue is established using a "building blocks" approach, adding all costs associated with the delivery service, but then adjusting the total to comply with our regulated price cap.

Transmission costs	FY27 ($000)	FY26 ($000)	Variation (%)
Benefit Based charges	1,876.0	1,706.8	+9.9%
Residual charges	12,894.1	10,554.0	+22.2%
Transition cap adjustment	8.0	6.6	+22.3%
Connection charges	384.9	358.6	+7.3%
New investment charges	57.4	57.8	-0.7%
Avoided transmission charges	0.0	0.0	+0.0%
Total	**15,220.4**	**12,683.8**	**+20.0%**

Distribution costs	FY27 ($000)	FY26 ($000)	Variation (%)
Administration (business support)	10,288.0	11,885.9	-13.4%
Operations and Maintenance	13,742.0	12,043.8	+14.1%
Export credits	13.5	0.0	New in FY27
Depreciation	14,134.8	13,599.0	+3.9%
Loss on disposals	300.0	300.0	+0.0%
Regulatory tax	3,222.6	2,855.9	+12.8%
Return on capital	15,888.8	15,215.2	+4.4%
Regulatory incentives and limits	-945.6	-6,252.6	-84.9%
Voluntary under-charging	-4,574.4	-17.2	NA
Total	**52,069.6**	**49,630.0**	**+4.9%**

The key drivers of the movements above include:

- The Commerce Commission's regulated price path phases in the allowable increase over the 5-year regulatory period with +10.7% annual increments as well as an inflation based allowance – this adjustment underpins the majority of the change in the Regulatory incentives and limits entry.
- We have significantly enhanced our voluntary under-charging in order to provide a smoother price path for customers and to further mitigate the impact of increases.
- Administration cost fluctuations are due to the one-off expected investments in FY26 to replace and update our finance management system, together with continued necessary investment in administrative areas.
- Operations and maintenance cost increases are due to increased expected maintenance costs in FY27 combined with a continued increase in network engineering resource and ongoing investments to replace our network mapping and control system.

- The regulatory tax allowance is expected to increase in line with DPP4 increased revenue allowances.

Transpower's regulated price path provides a similar step change to ours, except that the increase has been provided for over the first two years of the 5-year regulatory period. The 20% increase noted above is the second of these two step changes.

An additional factor driving the increase in the transmission benefit-based charge is the adjustments that have been applied for grid-scale solar farms. When these solar farms connect to our network they meet a portion of our energy needs, and we draw less energy from the grid. Despite using the grid less, the transmission pricing methodology set by the Electricity Authority requires Transpower to charge us more than we previously paid. In FY26 we paid $374k more and in FY27 we are forecasting to pay $419k more for using the grid less, and this additional cost is passed on to the solar farms that triggered the adjustments.

Combining the cost components above gives our total target revenue for FY27.

	FY27 ($000)	**FY26** ($000)	**Variation** (%)
Transmission costs	15,220.4	12,683.8	+20.0%
Distribution costs	52,069.6	49,630.0	+4.9%
Delivery costs (total)	**67,290.0**	**62,313.8**	+8.0%

7.2. Credits for export

The export credit cost listed in the previous section are payments in respect of injection from generation that is expected to mitigate peak demands that would otherwise drive the need for capacity reinforcement in the long term. The credits are required by the Code and intended to reflect the marginal costs of peak demand (on average and over time) that injection can avoid.

The credits are a "network alternative" – a cost that is incurred instead of the cost of a network solution. As such, the cost of providing the credits is allocated to customers that use the network (rather than just to the category of the exporting customer), and for this we use a similar approach to network cost allocations.

Compared to overseas jurisdictions, New Zealand operates within a relatively mature demand response framework. For many decades, customers have been incentivised to shift consumption through mechanisms such as day/night pricing, off peak tariffs, and controlled load options. These measures have successfully reduced diversified maximum demand and avoided the need for extensive capacity upgrades. Without such demand response and off-peak usage, significant reinforcement of network capacity would have been required.

We are required to link export credits to the long run marginal cost (LRMC) of assets that the injection avoids. A common approach to establish the LRMC is to assesses the value of capacity reinforcement projects included in Asset Management Plans (AMPs). However, this approach can be circular: if demand response signals are effective, the planned reinforcement expenditure is deferred or removed from the AMP, which in turn reduces or eliminates the calculated LRMC. This circularity is particularly problematic where reinforcement has already been avoided, as is the case in our network. In these circumstances, injections should be recognised as complementary to existing demand response measures and rewarded consistently on an equitable, non discriminatory basis.

To address this limitation, we have adopted an alternative LRMC estimation approach that provides stable, long term signals in line with the Authority's guidance. Our method applies a standardised network assessment, estimating the marginal cost of adding one kilowatt of capacity over and above constructing the network on a "greenfields" basis.

Our LRMC methodology steps are:

1. Identify network areas with load profiles that drive capacity planning and reinforcement.
2. Define the network tiers required to deliver electricity using standardised module sizes.
3. Determine the replacement cost of each module and estimate the portion attributable to load.
4. Annualise the load dependent portion of costs, including allowances for operations and maintenance.
5. Divide this annualised cost by the incremental kilowatt capacity provided by each tier, and aggregate across the tiers.

The sections below describe our assessment of these steps.

Credit areas

- Urban Ashburton – our network architecture is primarily underground and peak loads occur on winter evenings driven by a concentrated residential load profile. While the satellite towns have a similar urban network architecture, they are fed via our rural subtransmission system, so cost attributes are more aligned with our rural areas detailed below.

- Remote rural – we provide reticulation to several remote areas with low and stable demands. The standard conductor sizing (and in particular, the high voltage feed to the remote areas) provides a surplus of capacity, and the marginal cost of additional load is effectively nil.

- Rural Export constrained – in several areas of our network we have fully utilised the capability of the network to accommodate generation, and it is additional generation (rather than load) that would drive the need for capacity reinforcement. In these areas the LRMC of additional load is nil (or negative).

- Rural Load constrained – our network architecture in rural areas is characterised by long runs of interconnected 66kV subtransmission, relatively small zone substations, and radial 22kV distribution. Peak loads occur on summer afternoons driven by agri-business activities, and in particular the irrigation load.

The first and last of the areas listed above give rise to a LRMC that can (on average and in the long term) be offset though injection from generation that is aligned with the load peaks. These are considered further in the following steps.

The following tables set out steps 2 to 5 for the two areas that have a LRMC for load.

Urban Ashburton Area

The following table sets out the network tiers and our assessment of their load dependent cost. Of note for the urban Ashburton area, we have included a forward-looking capacity enhancement estimate for the low voltage network, which we expect will be needed to accommodate electrification of transport. We have also included an estimate for Transpower's Orari upgrade, as export will offset the extent to which those costs are assigned to EA Networks.

Network tier	Increment	Cost	Increment capacity kW	Annual cost	Proportion peak load dependent	Load dependent cost (at coincident peak)
Network connection and fusing	Urban LV pillar box with 2x60A fusing (sized for two properties)	$1,700	28	$139	10%	$0.5 /kW/yr
LV distribution	200m of LV 3 phase LV cabling 185mm2 Al XLPE	$32,000	100	$2,615	10%	$2.6 /kW/yr
LV Reinforcement	100m of LV 3 phase LV cabling 240mm2 Al XLPE	$45,100	100	$3,685	100%	$36.9 /kW/yr
Distribution transformer	300 kVA ground mount transformer with kiosk, RMU, & LV panel	$98,200	285	$8,025	27%	$7.6 /kW/yr
HV distribution	3 km of 11kV cable 150 mm2 Al XLPE	$454,000	4,000	$37,099	20%	$1.9 /kW/yr
Zone substation	Complete urban zone substation with 20 MVA firm capacity	$5,000,000	19,000	$408,581	50%	$10.8 /kW/yr
Subtransmission	8 km of 66kV overhead line, 66kV breaker bay, 6th of GXP bus	$1,760,000	40,000	$143,821	50%	$1.8 /kW/yr
Transmission connection			220,000	$360,000	0%	$0.0 /kW/yr
Transmission residual			220,000	$10,544,000	0%	$0.0 /kW/yr
Transmission benefit based			220,000	$1,710,000	0%	$0.0 /kW/yr
Transmission benefit based charges (new)	Orari upgrade stage, kW is the increment		200,000	$1,000,000	90%	$4.5 /kW/yr

In line with the regulation for credits, we then apply an adjustment factor to reflect specific circumstances and the extent to which we expect the export will address peak load related capacity costs.

Network tier	Adjustment factor	Basis
Network connection and fusing	0%	These assets are sized for a customer's own load, and there is no reduction in size when export occurs.
LV distribution	0%	These assets use standard sizing, and cannot be efficiently altered or alternatively utilised in the medium to long term.
LV reinforcement	67%	The anticipated need (in the absence of pricing/non-network solutions) to reinforce the existing LV network for a residential ADMD of 7.5 kW to cater for electrification. Adjusted to reflect locational alignment between generation and electric vehicle charging (that is, not all will align).
Distribution transformer	33%	Adjustment factor driven by location – we estimate that only 1 in 3 transformers are operating at a level that would exceed capacity in the absence of all demand response
HV distribution	33%	Adjustment factor driven by location – we estimate that only 1 in 3 feeders are operating at a level that would exceed capacity in the absence of all demand response
Zone substation	100%	Zone substation upgrade would be required in the absence of existing demand response (of which export is a part)
Subtransmission	100%	
Transmission connection charges	0%	In the short to medium term, there is no capacity constraint at our GXP
Transmission residual charges	0%	Export from generation is added back, so residual charges do not reduce the cost
Transmission benefit based charges (existing)	0%	Existing benefit based charges are locked in and not adjusted for additional export, and not increased if prior export ceases.
Transmission benefit based charges (new)	100%	Most new BBC are reduced by generation through lower network volumes.

Rural load constrained

Network tier	Increment	Cost	Increment capacity kW	Annual cost	Proportion peak load dependent	Load dependent cost (at coincident peak)
Network connection and fusing	1 x 60A pole fuse	$1,200	28	$98	10%	$0.4/kW/yr
LV distribution	100m of LV overhead line (underbuilt)	$10,000	100	$817	25%	$2.0/kW/yr
Distribution transformer	50kVA pole mount	$16,500	48	$1,348	40%	$11.4/kW/yr
HV distribution	10km of 22kV overhead line	$850,000	4,000	$69,459	20%	$3.5/kW/yr
Zone substation	Complete rural zone substation 10MVA	$3,000,000	10,000	$245,149	42%	$10.3/kW/yr
Subtransmission	25 km of 66kV overhead line, 66kV breaker bay, 6th of GXP bus	$4,395,000	40,000	$359,143	95%	$8.5/kW/yr
Transmission connection			220,000	$360,000	0%	$0.0/kW/yr
Transmission residual			220,000	$10,544,000	0%	$0.0/kW/yr
Transmission benefit based			220,000	$1,710,000	0%	$0.0/kW/yr

In line with the regulation for credits, we then apply an adjustment factor to reflect specific circumstances and the extent to which we expect the export will address peak load related capacity costs.

Network tier	Adjustment factor	Basis
Network connection and fusing	0%	These assets are sized for a customer's own load, and there is no reduction in size when export occurs.
LV distribution	0%	These assets use standard sizing, and cannot be efficiently altered or alternatively utilised in the medium to long term.
Distribution transformer	0%	In a rural setting, the transformer is sized for load, and with limited sharing, capacity that is liberated through export from generation cannot be alternatively utilised.
HV distribution	80%	Significant congestion with coincident peak load. However, the defined period will not always capturing peaks.
Zone substation	80%	Significant congestion with coincident peak load. However, the defined period will not always capturing peaks.
Subtransmission	10%	Adequate capacity in place (in most areas) for the longer term and capacity is augmented by solar generation in adjacent export constrained areas.
Transmission connection	0%	In the short to medium term, there is no capacity constraint at our GXP
Transmission residual	0%	Export from generation is added back, so export from generation does not reduce our residual charge allocation.
Transmission benefit based	0%	Existing benefit based charges are locked in and not adjusted for additional export, and not increased if prior export ceases.

Summating each load dependent cost multiplied by the relevant adjustment factor gives a total of $44.9 /kW/year in the urban Ashburton area, and $11.9 /kW/year in the rural load constrained area.

Capacity related costs are driven by the peak loads that occur, and we target the credit to provide an export incentive at these times. Ideally, we would be able to dynamically signal when the peaks are occurring, but this brings with it a duration risk – the peaks are driven by weather, and it is only with hindsight that we can identify the actual periods of highest load. If we signal peaks as they occur, we will ultimately signal a longer or shorter duration that we are targeting (and a volume-based credit will provide an excessive or insufficient reward accordingly). While we expect more development in this area in future, we have instead identified fixed times for applying credits that cover the traditional times we have observed peaks. We must balance shorter credit durations (which produce a higher credit price and incentive for response) with a longer duration (which is more likely to capture when the peaks occur).

The following table sets out our credit periods and the conversion to a volume-based credit.

Area	**Demand based credit ($/kW/year)**	**Peak window and credit period**	**Average hours per year (h/year)**	**Volume based credit ($/kWh)**
Urban Ashburton	44.9	5pm to 8pm, Monday to Friday, June to August	195.0	0.2301
Rural load constrained	11.9	2pm to 6pm, Monday to Friday, November & December	171.4	0.0692
Rural export constrained	0			0
Remote rural	0			0

The following explains how dividing the annual kW-based credit by the annual duration gives a volume-based credit price:

$$\frac{\$/\text{kW/year}}{\text{h/year}} = \frac{\$/\text{kW/year}}{\text{h/year}} \times \frac{\text{year}}{\text{year}} = \$/\text{kWh}$$

7.3. Connection categories

We have identified situations where groups of customers place significantly different demands on delivery assets, and situations where customers use different sets of those delivery assets.

One of the aims with establishing these consumer groups is to support pricing that is subsidy free. Prices that reflect each category's contribution to costs ensure that customers are not paying more than the stand-alone cost, nor less than the incremental cost of supply (and all customers benefit from the presence of other categories that pick up a share of common costs).

Our categories are:

- General supplies
    - 8 kVA
    - 20 kVA
    - 50 kVA
    - 69 kVA
    - 100 kVA
    - 150 kVA
    - 300 kVA
- Irrigation
- Industrial
- Large User
- Generation
- Street lighting

We set out the criteria for allocating connections between the categories in our Electricity Delivery Pricing Application Guide available on our website. The approach is flexible as it allows many customers to choose which customer segment they belong to, and within each segment there is additional choice provided by way of connection sizing (fuse size), uncontrolled energy supply and controlled energy supply. Each incentivises a customer to make appropriate choices to get the most benefit.

> *For example: a customer in the General load group can reduce their variable line charges by selecting Controlled Energy supply. They can further reduce their line charges by making decisions about their connection fuse sizing – by reducing their load requirements they can reduce their line charges.*

The rest of this section describes each of these categories, the rationale for maintaining the category, and the key metrics for the category. The metrics are used for the subsequent asset and cost allocations.

General Supplies

This category caters for the majority of our residential and small business connections. These supplies connect to our low voltage network and make use of all network assets (except lighting circuits).

Network supply assets are extensively shared (rather than dedicated) and there is significant diversity between individual customer's loading peaks. For example, while an individual residential connection might have a peak load of 12 kW, when combined in a pool of residential customers the combined peak equates to less than 3 kW for each customer.

We do not attempt to distinguish between residential and business supplies within this category because the distinction is very subjective as the line between business and residential premises is not clear, and the distinction does not drive any of our underlying costs.

Within the General Supply category we maintain several subcategories reflecting the capacity that we make available for each connection. Customers select the fused capacity that they need, and connections are assigned to the corresponding subcategory.

Further customer choice is provided by way of controlled load options. Customers can elect to cede control of specific appliances (for example, storage water heaters) in exchange for a lower volume price. We also provide a "TOU" day vs night and weekend pricing plan that allows customers to save by shifting discretionary load away from our peak usage periods.

For the residential customers within the General Supply category, the most common combinations of volume price options are:

Tariff option combinations	**Number of customers**	**Proportion**	**Proportion last year**
Anytime with Peak control	7,767	56.6%	59.4%
Anytime	2,219	16.2%	15.7%
Anytime with Peak control and Night only	1,693	12.3%	13.6%
Anytime with Night only	897	6.5%	7.0%
Anytime with Night boost	188	1.4%	1.4%
Anytime with Peak control and Night boost	136	1.0%	0.8%
Anytime with Night only and Night boost	61	0.4%	0.4%
Day, Night and Weekend	171	1.2%	0.9%
Day, Night and Weekend with Peak control	196	1.4%	0.6%
Day, Night and Weekend with Anytime and Peak control	251	1.8%	0.0%
Day, Night and Weekend with Anytime	37	0.3%	0.0%
Day, Night and Weekend with Peak control and Night only	31	0.2%	0.0%
Day, Night and Weekend with Night only	26	0.2%	0.0%
Day, Night and Weekend with Anytime and Night only	30	0.2%	0.0%
Other	20	0.1%	0.3%
Total residential customers	**13,723**		

Notes:

- This snapshot is taken prior to the requirement to apply time-varying pricing. For FY27, we expect the majority of Anytime usage will instead be charged as Day, Night and Weekend. Retailers are not required to reflect this in retail accounts, and we now have no way to determine what style of retail price plan each customer is using.
- Residential ICPs represented in this table are selected based on the electricity retailers' ANZSIC coding.
- The results include tariffs that are installed but may be unused.
- Residential customers with just an "Anytime" tariff will include those that have gas water heating.

The overall metrics for the category are:

Forecast key metrics for general supplies (1 April 2026 to 31 March 2027)		**8 kVA**	**20 kVA**	**50 kVA**	**69 kVA**	**100 kVA**	**150 kVA**	**300 kVA**
Number of connections / ICPs		445	16,367	1,846	364	469	211	108
Energy volume	MWh	1,984	128,631	29,121	20,090	47,125	25,285	15,290
Peak demands								
sum of installed capacity (∑Capacity)	kVA	3,429	270,060	78,442	23,683	49,532	32,051	27,626
sum of anytime peaks (ΣAMD)	kVA	1,826	114,571	36,914	20,372	42,175	27,430	21,600
contribution to local network peak (ADMD)	kVA	305	24,666	5,057	3,240	8,667	5,492	2,959
Value of lost load (VOLL)	$/kWh	14	14	18	19	20	22	22

Irrigation connections

Irrigation represents a significant part of our network load, consuming 32% of our total network volumes and 63% of our coincident maximum demand. We maintain a specific category for these connections to reflect the unique characteristics of their electrical loads and rural location. Of note:

- they are in lower density rural areas (using relatively long stretches of overhead network),
- their load is seasonal and highly correlated, there is little loading diversity,
- their load and combined loading peaks are very flat (and any load management or demand response that aims to reduce these peaks must therefore operate for extended periods of time to be effective), and
- their peak demands occur in summer and drive our overall network peak, eclipsing the rest of our connection categories which are mainly winter peaking.

This category generally applies to all irrigation connections with a capacity greater than 20 kW.

Irrigation is seasonal and weather dependent. Irrigation typically starts during September/October and ends around March. Irrigation reduces during periods of wet weather and can be at full capacity for days or weeks through the season during dry conditions. However, during drought conditions, irrigation load tends to reduce as users face water restrictions.

We are also aware that a few irrigation connections are maintained as a backup for other water supplies. We must maintain and reserve the capacity in our network for these irrigation pumps even though they are infrequently used.

Although feedback from customers has shown us that irrigation is not a suitable load to manage in response to peaks, we assess it as having a relatively low “value of lost load” in response to occasional interruptions.

Forecast key metrics for irrigation connections (1 April 2026 to 31 March 2027)	
Number of connections / ICPs	1,627
Energy volume	192,340 MWh
Peak demands	
sum of installed capacity (∑Capacity)	217,733 kVA
sum of anytime peaks (ΣAMD)	141,526 kVA
contribution to local network peak (ADMD)	107,081 kVA
Value of lost load (VOLL)	$6.0 /kWh

Industrial connections

Our industrial connection category caters for larger connections that generally connect directly to a distribution transformer, and often have a transformer dedicated for their use.

The separate category allows us to reflect the fact that they do not utilise our low voltage network, and also allows us to make use of the higher-grade metering information that is available for these larger connections (where we have access to kVA loadings on a half-hour basis).

Customers are able to select the capacity that is reserved for their use, and our charges are then linked to this selection. To avoid an artificial discrimination (or distortionary incentive), customers near the boundary with the General Supply category (those with 300 to 500 amp fusing) are able to select which pricing option applies for their connection.

We assess these supplies as having a relatively high value of lost load (VOLL), and the back-up assets that we provide to improve security and resilience are relatively more important for these customers.

Forecast key metrics for industrial connections (1 April 2026 to 31 March 2027)		
Number of connections / ICPs	54	
Energy volume	46,556	MWh
Peak demands		
sum of installed capacity (∑Capacity)	23,070	kVA
sum of anytime peaks (ΣAMD)	16,380	kVA
contribution to local network peak (ADMD)	7,937	kVA
Value of lost load (VOLL)	$23	/kWh

Large users

Stepping up from the industrial category, we individually consider connections where the capacity exceeds 2 MVA, that have a high voltage connection, or where the configuration of the supply differs significantly from our standard approach.

This approach allows us to reflect the specific circumstances of each connection, and to individually consider the costs that are then assigned. We do this in a transparent way so that these customers can see and anticipate the impact of their capacity needs. Of note, it is the cost allocation that is relevant, because once costs are allocated, the connection specific pricing structure uses a fixed approach to recover the target amount (unlike other categories, there is no need to structure pricing to ensure different members of the category pay an appropriate amount).

As a category total, these customers are summer peaking, which reflects the alignment with the summer peaking agricultural industry in our area. We also assess the VOLL for theses supplies individually, with most attracting a relatively high value.

Forecast key metrics for large users (1 April 2026 to 31 March 2027)		
Number of connections / ICPs	10	
Energy volume	85,432	MWh
Peak demands		
sum of installed capacity (∑Capacity)	35,960	kVA
sum of anytime peaks (ΣAMD)	26,517	kVA
contribution to local network peak (ADMD)	19,200	kVA
Value of lost load (VOLL)	$15 to $30	/kWh

Generation

On a similar basis to the large user category, we maintain a separate category for dedicated large scale generation customers. This separate categorisation allows us to reflect the incremental cost obligations that the Electricity Authority requires us to apply – these customers do not make any contribution to common costs. We apply an exception to this where the customer also has load, and we allocate costs for this load in the same way that we would for stand-alone load of the same magnitude.

We individually identify the assets that are incrementally provided for the generation connection and assign costs based on this allocation. In some cases we must then apply an adjustment to align with a previously contracted charging amount. Pricing is then applied using a fixed connection specific approach to ensure it matches the target cost allocation.

We assess these customers as having a relatively low VOLL. During an interruption, their ability to export energy is affected, but there is limited consequential impact on other processes, plant, or stock. On this basis, the VOLL for lost export would be close to the energy price. In this methodology, VOLL is only used as a weighting to the allocators against load. Some generators utilise our supply as an ancillary backup feed, and the VOLL in the table below is a load-only VOLL relating to times when the generator is drawing from our network.

Forecast key metrics for generation connections (1 April 2026 to 31 March 2027)	**Load**	**Export**
Number of connections / ICPs	9	
Energy volume	337 MWh	267,572 MWh
Peak demands		
sum of installed capacity (∑Capacity)	492 kVA	
sum of anytime peaks (ΣAMD)	284 kVA	126,314 kVA
contribution to local network peak (ADMD)	41 kVA	
Value of lost load (VOLL)	$12 to $16 /kWh	

7.4. Asset allocation

As a preliminary step in allocating costs between connection categories, we first allocate assets between connection categories. This is an important step in the process, and the allocation approach informs the subsequent step of setting cost reflective pricing components:

> *"we aim to allocate assets reflecting the way that connection categories drive the need for investment, and then we set a matching pricing structure so that customers bear or benefit from the decisions they make about using our service"*

Many of our assets are sized to meet peak loads. Assets that are close to the customer are sized to meet the peak load of the customer, whereas upstream assets (like our sub-transmission and zone substations) are sized to meet the diversified peak load of all connected customers – the after diversity maximum demand (ADMD). This is best illustrated with residential connections, where we typically provide 14 kVA fused capacity for each customer, allow for a peak of 5 kVA per customer throughout the low voltage network, and build for just 3 kVA per customer at the zone substation level.

A second consideration is our provision of backup assets. In our upstream network we effectively duplicate the supply capacity to avoid or limit the impact of outages, and to keep the power on during planned maintenance. Customers value this security and reliability differently, and we reflect this in our asset allocation.

Finally, some assets categories are not used by some connection categories, and we reflect this in our allocation.

In summary:

- we itemise and allocate dedicated assets to the connection categories that use them,
- we consider the relative use that each connection category makes of each asset category and weight the allocation accordingly,
- the allocation of assets that are largely shared (e.g. sub-transmission assets) is weighted more in favour of each category's contribution to local peak demands (ADMD) on the basis that these assets are sized to meet the combined coincident loadings,
- the allocation of assets that are sized to meet the load of individual connections (for example low voltage assets), and those assets that tend to have a fixed size regardless of loading levels (for example land) is weighted more in favour of the sum of each individual connection's anytime peak (ΣAMD),
- the allocation of contingent assets (the assets that are provided to maintain supply after a fault) is additionally weighted in proportion to each category's value of lost load (VOLL), as this measure reflects the relative need for the assets between the connection categories.

The asset values for each asset category are based on the values in our most recent information disclosure, indexed through to the mid-point of the pricing year. The allocation is carried out using the replacement cost of assets, and then depreciation is shared in proportion to this initial allocation. This sharing of depreciation matches the approach that Transpower takes in relation to its connection charges, and reflects that we provide an ongoing service, rather than a service with diminishing value (in other words, a delivery service provided with older assets is no less valuable than a service provided with new assets).

The resulting allocations of depreciated regulated asset base are:

Asset Category ($000)	8 kVA	20 kVA	50 kVA	69 kVA	100 kVA	150 kVA	300 kVA
Subtransmission lines & cables	22.2	1,792.2	405.2	270.6	740.4	481.0	259.2
Zone substations	52.0	4,201.3	976.4	656.0	1,805.4	1,185.4	638.7
HV Distribution lines & cables	212.5	16,418.3	3,924.3	2,508.4	6,504.4	4,200.9	2,440.2
LV lines & cables	416.9	30,154.9	8,818.3	3,909.7	8,532.6	5,526.2	4,217.6
Distribution substations & transformers	316.3	22,782.5	6,784.8	2,936.3	6,324.0	4,110.9	3,206.6
Distribution switchgear	171.4	11,725.0	3,670.2	1,827.7	3,950.0	2,605.5	1,999.1
Other network assets	11.6	729.5	235.0	129.7	268.5	174.7	137.5
Non-network assets	93.2	5,846.0	1,883.6	1,039.5	2,152.0	1,399.6	1,102.2
Total	**1,296.1**	**93,649.7**	**26,697.8**	**13,277.8**	**30,277.3**	**19,684.2**	**14,001.0**
Share of overall total	0.3%	24.4%	7.0%	3.5%	7.9%	5.1%	3.6%

Asset Category ($000)	Irrigation	Industrial	Large Users	Generation	Street lighting	Total
Subtransmission lines & cables	8,654.8	710.0	2,171.6	6,125.5	9.3	**21,641.8**
Zone substations	16,038.1	1,758.3	4,962.1	6.4	22.2	**32,302.1**
HV Distribution lines & cables	54,280.5	5,551.2	6,799.4	335.1	76.4	**103,251.6**
LV lines & cables	8,866.6	3,105.3	0.0	0.0	1,841.6	**75,389.8**
Distribution substations & transformers	29,545.2	3,114.1	1,679.8	39.4	42.0	**80,881.8**
Distribution switchgear	15,684.5	1,913.7	857.1	73.0	25.9	**44,503.0**
Other network assets	901.1	104.3	168.8	1.8	1.6	**2,864.2**
Non-network assets	7,221.4	835.8	1,353.0	14.5	12.8	**22,953.6**
Total	**141,192.1**	**17,092.6**	**17,991.8**	**6,595.7**	**2,031.8**	**383,787.9**
Share of overall total	36.8%	4.5%	4.7%	1.7%	0.5%	100.0%

As a modification to the above, for large users and generation we take account of the value of assets that the customer has funded. While we do not charge for any return or depreciation on these assets, we must still manage the assets, incurring the normal range of administration, operations, and maintenance costs. This adjustment brings the totals to:

	Large Users	Generation
Total	**18,926.2**	**10,956.8**
Share of overall total	4.9%	2.8%

7.5. Allocating costs to connection categories

The sections 7.3 and 7.4 provide a range of metrics for each connection category that we can use to allocate costs. We individually consider each cost category and determine the most appropriate allocator to use.

This section transparently shows the allocators that we use for each cost category, and explains the rationality for selecting the allocator.

Transmission benefit-based charges

Under the TPM, benefit-based charges are allocated to transmission customers in proportion to an assessment of how each customer benefits. For most assessments, transmission customers are assessed to benefit in proportion to the value they derive from the lower volume prices that the relevant grid upgrade provides.

Translating this to our customers, each will benefit in proportion to the volume of electricity that they purchase. In line with this, we allocate the cost in proportion to each category's total energy volume.

Transmission residual charges

The TPM establishes the residual charge based on our peak demands between 2014 and 2018, and then adjusts this based on a four-year lagged and four-year averaged movement in energy volumes.

Of note:

- Basing the allocation on any measure of peak demand will understate the financial impact of subsequent energy volume changes.
- Our connection categories make significantly different contributions to peak demands and energy volumes (for example, irrigation has a much higher contribution to peak demands than it does to energy volumes).
- Our customers and their retailers have indicated a strong preference to be charged based on current loading levels, and would not accept being charged for the current period of service based on measurements from many years prior.

We consider that it is more important to adopt a forward-looking assessment using the metric that will affect how our charges change over time, and we are transitioning toward a volume-based cost allocation. This has a significant impact on price movements, and we are phasing in the change over time. In FY26 we paused the change to mitigate price shock when compounded with the underlying price movement. The allocation basis has been:

Financial year	ADMD Weighting	Volume Weighting
FY23	100%	0%
FY24	80%	20%
FY25	60%	40%
FY26	60%	40%
FY27	50%	50%

Transmission connection and new investment charges

These charges relate to the assets installed at the grid exit point, and are essentially a fixed cost. We have determined that an equitable allocation of this cost is to assign it to connection categories based on the sum of the connection capacities (∑Capacity) within each category.

Administration costs, operations, and maintenance

Our service is primarily asset management. Our activities revolve around administering, maintaining, and operating the network. On this basis, we have determined to allocate the related costs to each connection category in proportion to the allocation of assets (including an allowance for any customer funded assets that we maintain).

Asset costs (depreciation, return on capital, loss on disposals, regulatory tax)

We allocate our asset-based costs in proportion to our allocation of assets for each category. In this case we exclude the value of customer funded assets.

Export credits

Export credits are effectively a "network alternative" and all users of the network benefit from the avoided investment in network assets. Recognising that we provide credits in two distinct locations, we allocate the winter based urban Ashburton credits in proportion to each category's contribution to the coincident winter peak, and we allocate the summer based rural credits in proportion to each category's contribution to the coincident summer peak.

Compliance adjustments and voluntary undercharging

The vast majority of compliance adjustments relate to the operation of our assets, and wash-ups carried forward from previous periods, together with an overall limit on our revenue. The wash-ups represent an under or over recovery against our return on capital, and are therefore primarily an asset related cost. The overall adjustment, as well as our voluntary under-charging adjustment is allocated to address contractual obligations, to smooth transitions and to avoid rate shock, and the balance is allocated in proportion to allocated assets.

Item	**Amount ($000)**	**Allocation method**
Regulatory incentives and limits	5,527.8	Allocated in proportion to allocated assets
Compliance adjustment	(6,473.5)	Individual allocations made to align with contractual obligations (some large users have fixed price contracts), specific allocations to provide smooth transitions and avoid price shocks, and the balance is allocated based on allocated assets.
Voluntary undercharging	(4,574.4)	
Total	**(5,520.1)**	

(note that the figures in this table represent the absolute value of the components, whereas the table in section 2.2 shows the change from FY26 to FY27)

Resulting cost allocations

Applying the above allocation approaches to the target revenue amounts set out in section 7.1 gives:

Target Revenue Category ($000)	**8 kVA**	**20 kVA**	**50 kVA**	**69 kVA**	**100 kVA**	**150 kVA**	**300 kVA**
Transmission benefit-based charges	4.9	316.0	71.5	49.3	115.8	62.1	37.6
Transmission residual charges	32.2	2,256.6	492.5	333.2	819.5	466.0	269.2
Transmission connection and new investment charges	2.0	156.7	45.5	13.7	28.7	18.6	16.0
Administration costs, operations, and maintenance	80.0	5,783.8	1,648.9	820.0	1,869.9	1,215.7	864.7
Asset costs (depreciation, return on capital, loss on disposals, regulatory tax)	113.3	8,185.8	2,333.6	1,160.6	2,646.5	1,720.6	1,223.8
Export credits	0.0	1.5	0.4	0.3	0.8	0.5	0.2
Compliance adjustments (wash-ups and allowances)	18.7	1,348.9	384.5	191.2	436.1	283.5	201.7
Compliance adjustment (reduction to comply with price path and voluntary under-charging)	(7.6)	(3,684.4)	(1,250.0)	(280.0)	(800.0)	(900.0)	(750.0)
Total	**243.5**	**14,364.8**	**3,727.0**	**2,288.5**	**5,117.4**	**2,866.9**	**1,863.2**
Share of overall total	0.4%	21.3%	5.5%	3.4%	7.6%	4.3%	2.8%

Target Revenue Category ($000)	**Irrigation**	**Industrial**	**Large Users**	**Generation**	**Street lighting**	**Total**
Transmission benefit-based charges	472.4	114.4	209.8	419.5	2.7	**1,876.0**
Transmission residual charges	5,815.9	782.3	1,613.3	5.2	16.2	**12,902.1**
Transmission connection and new investment charges	126.3	13.4	20.9	0.3	0.1	**442.3**
Administration costs, operations, and maintenance	8,720.1	1,055.6	1,168.9	676.7	125.5	**24,030.0**
Asset costs (depreciation, return on capital, loss on disposals, regulatory tax)	12,341.3	1,494.0	1,572.6	576.5	177.6	**33,546.2**
Export credits	7.3	0.7	1.6	0.0	0.0	**13.5**
Compliance adjustments (wash-ups and allowances)	2,033.6	246.2	259.1	95.0	29.3	**5,527.8**
Compliance adjustment (reduction to comply with price path and voluntary under-charging)	(1,100.0)	(744.0)	(907.0)	(594.9)	(30.0)	**(11,047.9)**
Total	**28,417.1**	**2,962.6**	**3,939.3**	**1,178.3**	**321.4**	**67,290.0**
Share of overall total	42.2%	4.4%	5.9%	1.8%	0.5%	100%

The total row in the table above is the target revenue for each connection category.

7.6. Subsidy free test

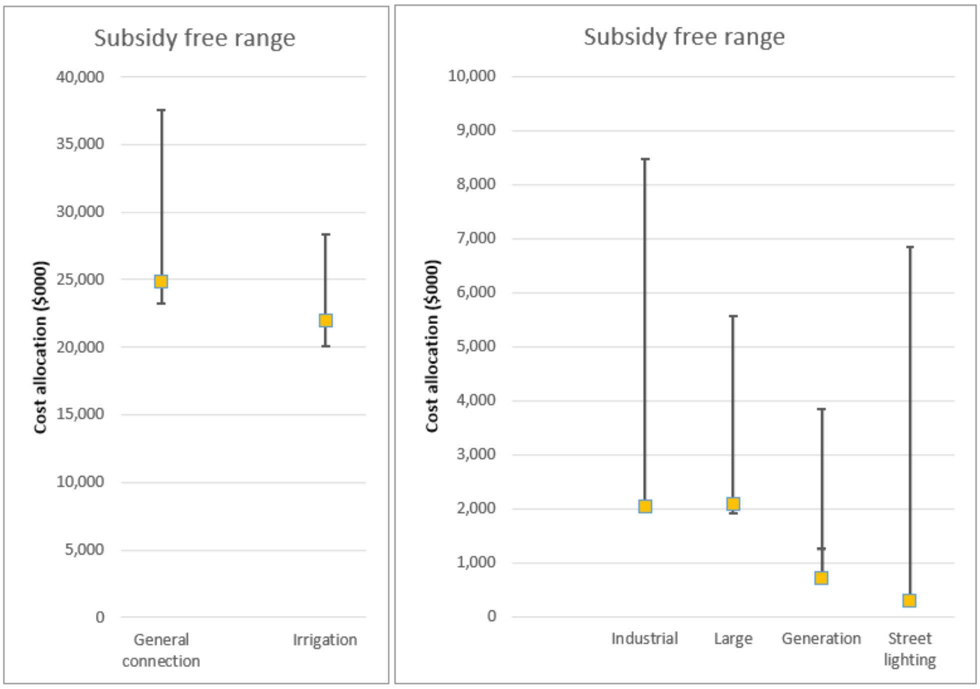
Before setting prices to recover the costs allocated above, we first check that the cost allocation falls within the subsidy free range. We aim to set prices so that customers are not paying more than the stand-alone cost, nor less than the incremental cost of supply. While we might receive a different level of profit from each category, this approach ensures that all customers benefit from the presence of other categories that pick up a share of common costs.

We undertake this test on a consumer group level, focusing on our connection categories as established in previous sections. For each category we consider and evaluate the network assets and costs that would be required if all other categories were removed. This provides a stand-alone cost (SAC) estimate for each.

We then come from the other direction, and assess the costs that would be avoided if each category did not exist, but we still maintained a service for all other categories. This provides an avoidable cost (AC) estimate (which is analogous to incremental cost for the category).

We then check that our cost allocation falls within the range, and this, in turn, ensures that the prices set to recover the cost allocation will also fall within the subsidy free range.

For the current pricing update, our assessment of the subsidy free range and assigned costs is described in the following charts.



Of note, all categories attract costs that fall within the subsidy free range except generation, which falls slightly below. This occurs because we are bound by contractual obligations based on prior cost assessments which differ from our current model. Unlike other categories, the Code requires us to set pricing that is no higher than avoided costs, so the divergence here is very minor.

It is also worth noting that streetlighting proportionally attracts a very high stand-alone cost. This occurs because the geographically spread nature of the supply means that most of our network would need to be in place to provide this service in isolation of the other categories.

The Industrial and Large User categories attract costs that are relatively close to our assessment of avoided cost. This is recognised in our model and these categories attract a proportionally higher price increase as we progressively address this imbalance.

7.7. Establishing target prices and structures

Setting price structures and prices is a key step in our methodology. The prices are our primary interface with customers. They influence customer's decisions about where and when to use electricity, or an alternative. The structuring of prices is a delicate compromise between the pricing strategy, economic considerations, sustainability and decarbonisation goals, customer preferences, equity and fairness, vulnerable customers and regulatory considerations set out in section 3.

There are two main steps:

- first, we set pricing components that reflect costs (that is, a change in customer behaviour is rewarded or charged at a level which reflects the cost impact on the service that we provide),
- then we set non-distortionary pricing components to recover the balance of our revenue requirement.

This section sets out an overall link to our network architecture, and then develops cost reflective target prices and structures, as well as residual pricing structures. This development informs the following section, where other considerations and limitations are applied in order to set prices against forecast quantities that achieve the target revenue.

Network context

We have one supply point from the transmission grid. A 33kV and 66kV sub-transmission network supplies 24 zone substations varying in size from 5 MVA to 40 MVA. The distribution network is a mixture of 22kV, 11kV and low voltage (LV) with both overhead and underground variants of each. Overall, the distribution system is about 24% underground cable by circuit length.

The main urban area in the district is Ashburton township, with about 20,000 residents. Smaller towns of Methven (1,900 people) and Rakaia (1,600 people) are also significant in terms of residential electricity consumer count. The district has a total population of about 35,000 people.

The area we serve is largely rural land used for cropping and dairy farming and has a high level of irrigation. Other significant loads are vegetable and meat processing facilities, and a ski-field.

Agriculture and irrigation

In recent decades dramatic load growth has occurred in the Mid-Canterbury region. The summer maximum demand has more than trebled since 1996 and more than doubled since 2003. The network has peaked at 181 MW twice in the past five years. Irrigation load has doubled since 2005 and has now reached an installed capacity exceeding 147 MW. This growth has in-turn driven significant capital development on EA Networks' network. However, irrigation load growth has now slowed, and we do not expect to see any further growth.

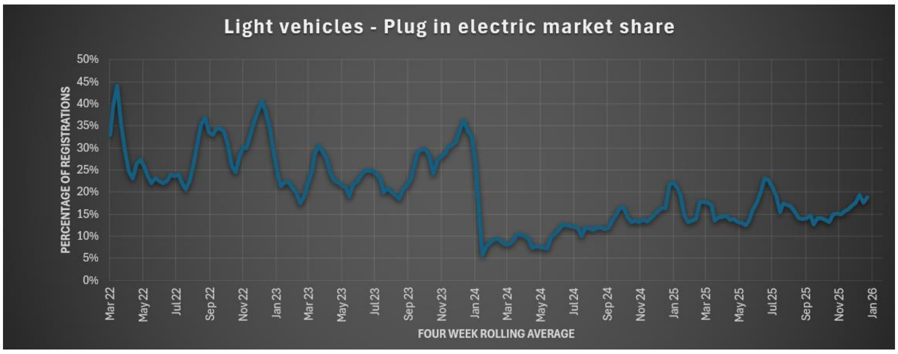
Electrification of transport

We predicted and have now observed that, alongside the removal of the clean car discount, the introduction of road user charges (RUC) for electric vehicles has significantly reduced demand for electric vehicles.

To illustrate the financial incentive that is reducing demand, the RUC rate for electric vehicles has been set at a higher rate than the fuel excise duty that a non-plug in hybrid or efficient petrol vehicle attracts. At current fuel prices, the running costs (energy and RUC) of an EV will approximately match that of an alternative petrol car that carries a lower capital cost. This equivalent running cost is based on home charging for the EV at 26c/kWh (retail, including GST). The average cost to use a public charger is around 75c/kWh, which would make the running cost of an EV higher than that of a petrol equivalent.

Electric vehicles also attract a higher registration licencing cost, and higher insurance premiums (with most providers) than petrol equivalents.

Registrations of new and imported electric vehicles clearly shows the change in uptake driven by current policy settings:



Source: https://www.transport.govt.nz/statistics-and-insights/fleet-statistics

The Government has signalled an intention to phase out fuel excise duty in favour of a universal RUC, but until this happens, we expect continued subdued activity in the EV charging space.

Electrification of process heat

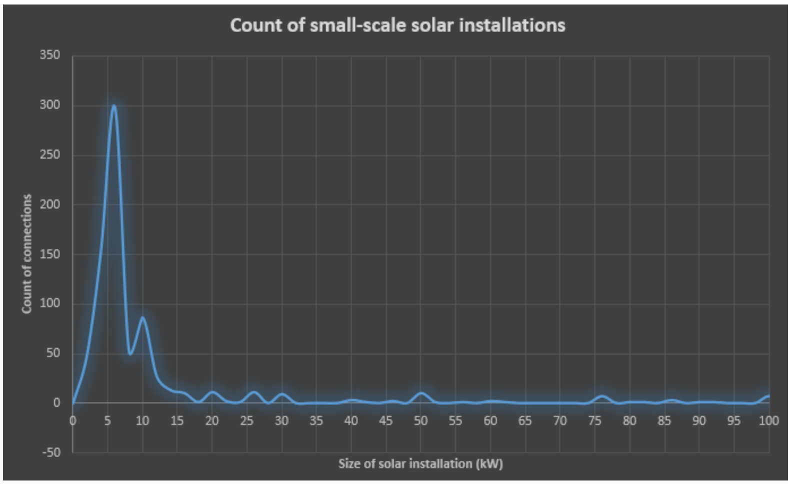
We anticipate a small number of larger conversions where customers will negotiate customised solutions with us directly. The timing of these remain uncertain, and we expect the recent volatility and high prices in the energy market will have given customers pause for thought.

Renewable generation

We anticipate continued uptake of large-scale distributed generation on our network. We have substantial capacity available to accept embedded generation in a flat rural setting, which makes us an attractive location for solar farms. Connecting to our network is a fraction of the cost of connecting to Transpower's grid, even where a distribution zone substation upgrade is required.

The first grid scale solar farm (Lauriston) was commissioned with a connection capacity of 47MW in December 2024, two further solar farms with combined capacity of 11MW were connected during 2005, and we have a further three farms with a combined capacity of 49MW are in the pipeline for 2026/27.

With a mixture of hydro and solar, we now have 90MW of large-scale renewable generation operating on our network. In addition to this, we have 10.9 MW of small-scale bespoke roof-top solar ranging from 1 kW to 940 kW, and growing:



Overview of Network Assets & Network Characteristics

EA Networks 2025-2035 Asset Management Plan (AMP) comprehensively describes the network assets and network characteristics. The following overview is from that AMP:

Network Inputs and Outputs:

Maximum demand	182.9	MW
Annual delivered energy	674	GWh
Annual load factor	45	%
Subtransmission lines & cables	418	km
MV Distribution lines & cables	2,212	km
LV Distribution lines & cables	513	km
Distribution substations	6,767	substations
* Data as at February 2025		

Substations	**Transformers**	**Peak Load (MW)**	**Load characteristics**
Ashburton 66/11	2 x 10/20MVA	21	Supplies 60% of urban Ashburton and some outlying areas. The load has a winter peak consisting almost entirely of residential dwellings and commercial businesses.
Carew 66/22	1 x 10/15MVA 1 x 10/20MVA	16	Mostly summer peaking and irrigation based. The high general demand is a consequence of the large number and size of dairy sheds. Load exceeds firm capacity.
Coldstream 66/22	1 x 10/15MVA	12	Load exceeds firm capacity. The high general demand is a consequence of the large number and size of dairy sheds. The dominant load is irrigation pumps which are summer peaking.
Dorie 66/22	1 x 10/15MVA	11	Summer peaks with irrigation load. The high general demand is a consequence of the large number and size of dairy sheds.
Eiffelton 66/11	1 x 10/20MVA	13	Mostly irrigation.
Elgin 66/22	1 x 20MVA	4.4	Mostly irrigation and provides a backup supply for

Substations	Transformers	Peak Load (MW)	Load characteristics
			neighbouring substation areas. 6.5MW of solar generation connected.
Fairton 66/22	1 x 10/20MVA	9	Supplies rural residential, industrial, and irrigation load. The ex-Silver Fern Farm meat-works are now owned by a vegetable processing company, and indications have been given that the site will be developed for other commercial tenants. Previously, the industrial load was non-seasonal, but total load peaked in summer with irrigation load. Another vegetable processing plant forms the base load. 4.4MW of solar generation connected.
Fairton 66/11	1 x 10/20MVA	4	
Hackthorne 66/22	1 x 10/20MVA	15	The load is summer peaking and irrigation based. The high general demand is a consequence of the large number and size of dairy sheds. Maximum load currently exceeds firm capacity.
Lagmhor 66/11	1 x 10/15MVA	11	Mainly irrigation. Firm capacity exceeds maximum load.
Lauriston 66/22	1 x 10/20MVA 1 x 24/35 MVA	15 (-46)	Summer peaking due to irrigation demand. The high general demand is a consequence of the large number and size of dairy sheds. Lauriston was upgraded during FY25 to accommodate the new 47MW Lauriston solar farm. It is now peak export congested.
Mt Hutt 33/11	1 x 5MVA	3	Peaks in winter associated with ski-field activities. Maximum load exceeds firm capacity. Zero irrigation. Cleardale hydro generation is connected at 11kV. Switched firm capacity is sufficient for essential services of the major consumer.
Montalto 33/11	1 x 2.5MVA	2.5	A temporary substation located near the Montalto hydro power station. Supplied from Mt Somers via 22/33 kV step-up transformer.
Mt Somers 66/22	1 x 10/15MVA	3/6	Maximum load matches firm capacity. The load is balanced between extensive rural farms, Mt Somers township, and a couple of lime quarries. The load is slightly summer peaking due to the irrigation but remains close to the summer peak during winter due to the residential demand. Montalto 1.8MW Hydro generator connected via 22/33 kV step-up.
Mt Somers 22/33	1 x 5MVA	3	
Methven 66/11	1 x 10/15MVA	5	22 kV summer peaking due to irrigation demand. 11 kV winter peaking due to residential/tourism demand. The high general demand is a consequence of the large number and size of dairy sheds and related irrigation.
Methven 66/22	1 x 18/25MVA	4	
Methven 22/33	1 x 5 MVA	3	
Northtown 66/11	2 x 10/20MVA	14	Provides additional capacity and security to Ashburton township and immediate surrounds. Load is winter peaking in line with residential demand.
Overdale 66/22	1 x 10/20MVA	13	The load is summer peaking and irrigation based, although Rakaia township with its residential/commercial demand causes higher base loads than some other irrigation-serving substations.
Pendarves 66/22	2 x 10/20MVA	17	Irrigation load causes this site to summer peak at 10 times its winter peak. Firm capacity is available to all loads.
Seafield 22/11	1 x 5MVA	-	Dedicated to ANZCO's meat-works. Non-seasonal peak load.
Seafield 66/11	1 x 10/15MVA	8	
Tinwald 66 (22/11)	1 x 6/8MVA	-	A site for future use as a 66/11 kV substation. Presently for 22/11 kV security and 66 kV switching.
Wakanui 66/11	1 x 10/15MVA	8	A summer peak load; mostly irrigation.

As a summary of the pricing impacts relating to key developments identified in our AMP:

- Irrigation consents – to accommodate a rapid increase in irrigation load during 2000s and 2010s we upgraded our subtransmission to 66kV and our distribution to 22kV, and load grew, in most areas, to fully utilise the available capacity. More recently, Environment Canterbury has restricted water consents, and we are seeing very little increase. In some situations, surface supply is replacing deep well pumping, which reduces energy demand. There is limited need for us to signal future rural capacity upgrades within pricing.
- Electrification of transport – subject to changes in road user charges noted above, we anticipate a continued uptake of domestic electric vehicles, and we are forecasting the predominant charging mode to be overnight charging at home. At the same time, we are seeing residential loads increase with higher density housing and more energy intensive appliances. We have signalled the need to manage load including through pricing signals to mitigate the need to reinforce the urban low voltage network.
- Electrification of process heat – these generally occur where an electrical solution replaces a coal boiler, and tend to be significant upgrades. In terms of pricing, we negotiate the terms for upgrades individually, and utilise site specific large user pricing to reflect actual cost impacts. There is no need to apply any wider price signal to the smaller connection categories.
- Connection of grid scale solar – we have recently connected three grid-scale solar farms, and we are processing further applications. These fall under the regulated incremental cost approach, and we generally charge all capital costs up-front. No costs are passed to other connection categories, so there is no impact on pricing.

Additional information is available in our published Asset Management Plan, available at: https://www.eanetworks.co.nz/about-us/disclosures.

Locational pricing (urban vs rural)

Lower density rural areas require more assets for each customer served, and this in isolation would support a locational pricing approach to reflect the higher costs. However:

- we supply rural areas with lower cost overhead network solutions (whereas new urban networks tend to be higher cost underground cable networks),
- rural customers make a greater contribution when first connecting to the network. This up-front funding addresses the cost differential, and in our view, provides a clearer (actionable) locational signal than would otherwise be the case with locational delivery charges, and
- much of the existing remote network was funded via the Rural Electrical Reticulation Council (RERC) which operated from 1946 to 1993.

We apply cost reflective pricing where it will drive efficient behaviours that benefit our community. In respect of existing connections, introducing a pricing differential will not drive any economic efficiencies - once properties and plant are in place, they will continue to be occupied and used. A higher rural price would simply shift the cost burden without any underlying benefit.

Further, rural customers receive a lower level of service, with a greater number of faults and longer restoration times, which would make a higher price difficult to defend.

Finally, our customers, even the ones that would stand to benefit, have historically told us that they do not want locational pricing. Our townships exist as rural support hubs and it is the rural activities that drive our local economy. In more recent feedback we have observed a subtle shift away from this position, and we intend to explore this more closely over the next few years.

With these factors we have not applied a locational structure to our pricing.

Non-standard contracts

EA Networks provides its delivery service under its standard default distributor agreement (DDA) which is consistent across all electricity retailers. Some customers in the generation category are an exception, where a direct contract with the customer replaces or supplements the DDA. These non-standard contracts cover the specific requirements for these customers. We consider non-standard contracts in situations where large users require services that are not adequately detailed in our DDA.

The following is a summary of the non-standard contracts in place as at 1 April 2026:

Number of Connections	8 generation connections
Value of target revenue	$1,169 k
Pricing methodology	Historic incremental cost approach for one connection, contracted charge level for two connections, and actual incremental cost for the rest.
Consistency with the pricing principles	The incremental cost approach is consistent with the pricing principles but is at the extreme boundary of being subsidy free (incremental cost is analogous to avoidable cost). The contracted charge approach is not consistent with the pricing principles because the charge is now less than avoidable costs. It was established prior to the pricing principles being developed, and is based on the amount that the customer had previously paid for a direct connection to the grid.
Security of supply obligations	Standard security of supply obligations apply, except that dedicated assets tend to be provided under an “N security” approach, which avoids the cost of rarely used back-up assets but means that a single fault causes an outage that lasts for the duration of the repair time.

Capital contribution policy

We receive capital contributions for upgrades and network extensions, the basis of which is detailed in our New Connections and Extensions Policy available on our website.

In broad terms, the policy is structured so that customers buy-in to the existing network at a price that puts them on an equal footing with existing customers. This allows us to apply the same prices for existing and new customers without supporting an inherent cross subsidy. Significantly, it allows us to apply the same ongoing prices for both urban and rural customers, because the higher up-front contribution for new rural connections adequately addresses the cost differentials.

An exception to this is the connection of large-scale distributed generation. We are regulated to provide access for these customers at incremental cost. We set the capital contribution to cover all new assets, and then we set bespoke pricing to reflect the incremental cost of these assets and any other incremental costs that might arise.

First mover disadvantage

Within our pricing, we recognise and address the first mover disadvantage issue. This issue occurs where:

- the first customer in an area pays for an extension that can subsequently be used by others, or
- a customer pays for a capacity upgrade where spare capacity is created which can subsequently be used by others.

Within our ongoing delivery pricing, we address the issue by charging all customers the same prices, regardless of the order of arrival. The exception to this is for generation customers, where we have a legal opinion indicating that part 6 of the Code requires us to consider the incremental cost of each generating customer separately, in the order they have been added (we acknowledge that this differs from the Authority's interpretation).

Within our capital contribution policy we address the issue with "pioneer schemes". These schemes recognise situations where an initial customer funds an extension or upgrade within an initial period, and provides a refund where subsequent customers use the same assets. From 1 April 2026 our pioneer scheme framework has been modified to align with the regulated requirement in the Code. Prior to that date we operated a similar arrangement with a specific focus on rural extensions.

We have found pioneer schemes to be an effective mechanism which often leads to costs being shared at the outset (ie customers jointly approach us for extensions).

Data access

When establishing price structures we must consider the metrics that are available against which we can apply prices. Metrics must either be universally available, or we must apply default alternatives. Any default alternatives can create arbitrage opportunities. For example, a customer that has a high peak demand might elect to not allow smart metering to be installed to avoid that high peak demand from being measured.

For our irrigation category, smart metering is close to ubiquitous. From 1 April 2024 we adjusted our billing to incorporate a measured peak demand assessment. This approach allowed us to circumvent the restrictive data agreements (see below) and obtain the information directly under our default distributor agreement (for billing functions only). The information has allowed us to validate the chargeable capacities that we apply for the category, and since implementing the approach we have adjusted our charge metrics for 186 supplies (about 10% of the category) for a total additional annual charge of close to $750,000. This represents a significant improvement to the equity of our charging approach for the category, ensuring that all customers are contributing an appropriate proportion in relation to the capacity of their plant.

Wider access to the detailed information from smart/advanced metering is likely to provide further improvements and more pricing options. However, we do not currently have access to the data. The Electricity Authority's Default Distributor Agreement does not allow us to use the data as it restricts access to the data to staff that only work in the regulated distribution service (all our staff participate in activities beyond this limited scope). We are progressing negotiations to allow less restrictive access to this information, and we expect to be able to utilise the data more widely in our price setting and billing processes in future.

General supplies

The table below sets out the cost reflective price components and target prices for connections in the General Supply category.

<table>
<tr><th>Cost reflective price components</th><th>Target price</th></tr>
<tr><td> Capacity
A key determinant of cost is the capacity that we provide for each customer. Almost 70% of our asset related costs relate to low voltage assets that are relatively close to the customer.
Many of our network upgrades provide step changes in capacity, and often our new network design uses standard capacity sizing. While the marginal cost of connecting customers when the capacity is already available is low, it makes sense to treat customers equitably, and charge a similar price regardless of the order in which they arrive. Consistent with this, we aim to set capacity prices that reflect a long run forward looking assessment of cost.
Even where there is no demand growth, a capacity-based charge still establishes an appropriate trading price, appropriately rewarding a customer that reduces capacity and charging new customers a corresponding amount.
We believe that short term costs are better dealt with outside the pricing arrangements. Flexibility services can be procured via separate commercial arrangements, targeting specific areas and times when congestion occurs. These arrangements are much more flexible and dynamic than we could accommodate through pricing. </td>
<td>The average cost of low voltage assets per kVA of fused capacity is $34.5/kVA per year.</td></tr>
<tr><td> Contribution to coincident demand
A secondary determinant of cost is each customer’s contribution to our coincident peak demands. These coincident peaks influence our sizing and reinforcement of our upstream assets, particularly our zone substations and subtransmission systems. These assets make up about 25% of our total asset value.
The contributions to coincident peaks vary significantly between customers, and for individual customers, the contribution can vary from year to year, as behaviours of other customers change and the timing of the peak shifts (that is, a customer’s contribution to costs can change significantly even when their own behaviour remains unchanged).
While the asset costs are lower, the diversified load (which gives rise to the coincident peak demand that drives our cost) is only about 15% of the sum of fused capacities. Compared with the capacity measure above, this results in a relatively low quantity against a relatively high price. The average cost of upstream assets per kVA contribution to coincident maximum demand is $122.7/kVA per year.
To address the volatility issues, this cost can be spread over longer durations which typically reflect when the peaks occur. Spreading the $122.7/kVA cost over weekdays volumes (7am to 9pm, Mon – Fri, over a seasonal 6 month peak) equates to a price of 6.7c/kWh.
A more targeted approach, giving a higher price over a shorter duration, may be an option in future. This would require segmentation between summer and winter peaking areas which carries a significant administrative burden and customer impacts, especially around the changing boundaries as the configuration of the network is adjusted.
The need to signal future congestion on the low voltage network from electric vehicle charging is also a factor in the structure of pricing. </td>
<td>Reflecting contribution to coincident demand supports a weekday (Mon-Fri) volume-based price of 6.7c/kWh</td></tr>
</table>

<table>
<tr><th>Cost reflective price components</th><th>Target price</th></tr>
<tr><td>Transmission charges – Benefit based charges
Under the TPM, benefit-based charges are allocated to transmission customers in proportion to an assessment of how each customer benefits. For most assessments, transmission customers are considered to benefit in proportion to the value they derive from the lower energy prices that the relevant grid upgrade provides (effectively, in proportion to energy volume).
Translating this to our customers, each will benefit in proportion to the volume of electricity that they purchase. Reflecting the way this cost is allocated to us supports a volume-based approach for passing through benefit-based charges.
Our total benefit-based charge is $1.9m against a total annual volume of 593,292 MWh.</td><td>Reflecting benefit based charges supports a volume-based price of 0.30c/kWh (as a flat price, against all volumes).</td></tr>
<tr><td>Transmission charges – Residual charges
Under the TPM, residual charges are initially set based on our peak demands between 2014 and 2018, and then adjusted based on a four-year lagged and four-year averaged movement in energy volumes.
With this approach, and our usage profile, EA Networks has one of the highest residual charges relative to volume in New Zealand. An extra 1,000kWh used in year 1 (all other things remaining equal) will increase or charges by $5.25 in year 5, 6, 7 and 8.
Discounting this delayed liability to the year in which the liability is created equates to a cost of 1.57c/kWh.
If we do not reflect this cost in prices, then any savings a customer’s reduction in consumption creates would be shared among all customers within their category. More concerning, the cost of any significant increase in usage by a customer would be shared among others. These facts are at odds with the Electricity Authority’s assertion that transmission charges are “fixed-like”.</td><td>Reflecting residual charges supports a volume-based price of 1.57c/kWh (as a flat price, against all volumes).</td></tr>
</table>

To the extent that our cost reflective pricing approaches do not meet the target revenue requirement we apply residual charges. The aim with residual charges is that structures should share costs in a fair and equitable way and not influence customer behaviour. This is a challenging balance.

The following table sets out and assesses the main options for residual charges and concludes the best approach(es) for the General Supply category.

<table>
<tr><th>Residual charge structures</th><th>Structure</th></tr>
<tr><td>Installed capacity (fuse based) pricing

An installed capacity charge (either based on fused kVA, or categories of fuse size) is effectively applied as a fixed charge. It distinguishes between customers that utilise our network to a different extent. There is limited distortionary incentives because a customer will generally select an installed capacity to meet the needs of their premise or plant.

However, it is not free from distortionary incentives.

Customers can manage their load to smooth it out, reduce their fuse size and reduce the amount they pay (and in relation to residual charges, without reducing any of our costs).

Similarly, customers can invest in batteries to smooth out their load, are incentivised to amalgamate multiple supplies to benefit from load diversity, and may seek to seasonally adjust their fused capacity (and reduce charges).

Focusing on fused capacity will also see customers reducing capacity to be closer to their actual peak demands. This will inevitably lead to outages when demand exceeds capacity (and current fusing is not customer resettable).

Further, it is administratively difficult to maintain records of fuse sizing with multiple parties having access to change fuses. An outage is often required to check or change fuse size, and any upgrade requires an assessment of safety within the premise (as an additional overhead).

Advanced metering does not provide a good indication of appropriate fuse sizing (because fusing can trip over a much shorter duration than the half-hour average loading available from advanced metering).

Optimising fuse sizing can limit the extent by which the customer has access to flexibility services (including controlled hot water heating). This is because any external control of loads might shift usage to times when the customer’s discretionary load is high and therefore exceed the fused capacity.

Despite these qualifications, installed capacity is our leading contender for non-distortionary collection of residual charges.</td><td>Grouping customers by fused capacity and applying a fixed daily charge</td></tr>
<tr><td>Measured anytime maximum demand

An alternative to using the fused capacity is to instead base charges on a measured maximum loading level. This eliminates some of the issues noted for fused capacity above, however it carries a range of its own issues.

For the General Supply category we don’t currently have access to metered maximum demand metering from advanced metering and the default data agreement that the Electricity Authority has put in place means that we have not yet been able to get access to that information in a usable way.

Not all premises have metering that records maximum demand levels, and an alternative would need to be maintained (which creates an incentive to select the type of metering that minimises costs).

An added challenge is that any third-party management of load (including our current management of water heating load) can set peaks that would then become chargeable. While it is possible to separately meter these managed loads, this is unlikely to be possible with new technology (that is, new loads like EV chargers are unlikely to be separately wired from the meter board, and are unlikely to be separately metered in a revenue-compliant way).</td><td>Measured AMD charging is not currently a viable option for the General Supply category</td></tr>
</table>

Residual charge structures	***Structure***
Fixed daily charges A simple fixed daily charge is often promoted as a solution (including in the Electricity Authority's guidance), but this leads to very small customers contributing the same amount as very large customers, which is inequitable. It would be grossly unfair and unpalatable for us to charge the same amount for a one-bedroom social housing unit and a large department store.	Simple fixed daily charging is not appropriate where the connection category that spans different size connections
Volume-based pricing Volume-based pricing has traditionally been used to share around residual charges in an equitable way. It provides a basis where customers that derive more benefit (ie use more electricity) contribute more to residual costs and overheads. Volume-based charges are understood and accepted by customers. In the past, volume charges were not distortionary, as there were limited options for customers to change their usage behaviours. This is changing, and customers now have more choices: • Moreso than in the past, electric space heating options now compete with traditional heating fuels, • Photovoltaic generation (PV) is available as an alternative. The Electricity Authority has expressed concern about the inefficient incentive that volume-based residual charges create for installing PV, and we share this concern. While we do see a degree of uptake, it has not occurred at the forecast rate that has been referenced so far. Volume-based pricing also carries some indirect benefits. It encourages energy efficiency and insulation, which provides community benefits that go beyond our electricity delivery service. While volume-based pricing overstates the incentive for PV, new renewable generation is needed in order for us to meet our decarbonisation goals (and customers investing in PV might not otherwise make an investment that helps decarbonise). Also, particularly for our summer peaking load, PV generation will help reduce the energy price that all within our community pay. This socialised benefit offsets the socialised cost of the inefficient incentive to install PV generation.	Applying a universal volume price remains a candidate for residual charges. Applying a price during weekdays (Mon-Fri) focuses the cost more toward business and commercial customers

Residual charge structures	***Structure***
Lagged and averaged volume-based pricing The Electricity Authority has promoted a lagged and averaged approach for volume pricing to address the distortionary influences. Although charging based on usage from several years prior and using an average over a period of time would reduce (but not eliminate) the distortionary incentives, in our view it would carry a range of new issues: • It creates a residual liability when a customer leaves the network that would be difficult to collect (and a mandated core term in the default distributor agreement prevents us for charging in respect of an ICP that is disconnected). • It is unclear how a customer entering an existing premise, or shifting to a new premise should be treated with respect to prior usage (by others) at that premise. • Customers tell us that it is not acceptable when changes in consumption do not align with changes in charges (they do not want to continue paying high charges for years after they reduce consumption, and they do not tolerate increases in charges that relate to higher usage patterns from many years prior). • It is not possible for us to treat new customers and existing customers differently, because it is often impossible for us to distinguish between a new customer and an existing customer that has simply shifted to a new retailer under a different name. • Retailers tell us that they would not be comfortable if their charges were derived from past metering undertaken by another retailer. They would not be able to check or challenge that metering, and would not be able to reflect that same chargeable quantity in their charges to customers (they generally don't pass on our charges, they instead create structures that match our structures, and cannot do that where they don't have access to the chargeable quantities). We have customers of all sizes entering and exiting, shifting premise, and morphing into different entities. A complex matrix of rules would need to be established and policed to prevent gaming of loopholes that delayed and average charges would create.	Delayed and averaged volume charging is not a viable option, and never will be.

Irrigation supplies

The table below sets out the cost reflective price components and target prices for connections in the irrigation category.

Cost reflective price components	***Target price***
Pump motor capacity Irrigation supplies tend to operate with little diversity (that is, we reach a point where almost all irrigation pumps are running at the same time). As such, it is the actual load of the pump motor that drives our cost in both localised and upstream network capacity. Our model shows that we allocate $12.3m in costs for local and upstream assets for irrigation supplies, maintaining capacity for pump motors with a capacity of 142 MVA. This equates to a price of $87/kW per year. Fuse size is not a good reflection of costs because pump motors need varying degrees of excess capacity to accommodate their very short duration start-up loads. These start-up loads do not drive our costs because the duration is very short and exhibit complete diversity (the number of pumps starting at the same time is never sufficient to create an observable peak in our network load).	The average cost of capacity related assets is $87/kW per year (based on the capacity of the pump motor).

Cost reflective price components	*Target price*
Metered maximum demand We observe that the equipment installed at irrigation connections is becoming more diverse with rig drives, booster pumps, air conditioning, SCADA and communications equipment. The loading of this equipment is difficult to quantify and add to the pump motor capacity. An alternative is to consider the metered maximum demand. However, this does not show reserved capacity (that is rarely used), so the measure is more useful to augment the assessment of the electrical load of installed equipment, rather than to set the chargeable loading level itself. An added challenge is that advanced metering is less accurate over short intervals. The transformation multipliers mean that the measured load often jumps in 5kW to 10kW increments over half hour periods. Metered peak loads need to be assessed and averaged over several hours to provide an appropriate level of accuracy, but this approach hides the fluctuations (and peaks) that occur within the averaging period.	Same as pump motor assessment above.
Harmonic mitigation We must restrict the levels of harmonics on our network. For the small number of irrigation connections that do not have harmonic mitigation equipment installed we apply a price premium set at a level that makes remediation financially viable, which we have assessed as $36.50/kW per year. Taking this approach ensures that the extra charge generally reflects the costs of mitigation (acknowledging that it is much more cost effective for the mitigating equipment to be installed by the customer at the location of the pump).	$36.50/kW per year
Transmission charges – Benefit based charges Under the TPM, benefit-based charges are allocated to transmission customers in proportion to an assessment of how each customer benefits. For most assessments, transmission customers are considered to benefit in proportion to the value they derive from the lower energy prices that the relevant grid upgrade provides (effectively, in proportion to energy volume). Translating this to our customers, each will benefit in proportion to the volume of electricity that they purchase. Reflecting the way this cost is allocated to us supports a volume-based approach for passing through benefit-based charges. Our total benefit-based charge is $1.9m against a total annual volume of 593,292 MWh.	Reflecting benefit based charges supports a volume-based price of 0.30c/kWh (as a flat price, against all volumes)
Transmission charges – Residual charges Under the TPM, residual charges are initially set based on our peak demands between 2014 and 2018, and then adjusted based on a four-year lagged and four-year averaged movement in energy volumes. For irrigation customers we have access to half-hour metering information which provides the option to charge based on measured demand levels. This allows us to emulate the averaging approach taken in the TPM and apply an average demand charge. Unlike the capacity charging approach noted above, average demand charging more fairly allocates shared transmission costs as customer demands change. It ensures that customers who increase their consumption bear the added costs that the change attracts, and also rewards customers that are able to reduce consumption through things like energy efficiency and renewable generation. Aligning with the method used to determine our residual charge in the TPM, a customer increasing their average demand by 1 kW throughout year 1 (all other things remaining equal) will increase our charges by $46.01 in year 5, 6, 7 and 8. Discounting this delayed liability to the year in which the liability is created equates to a cost of $137.31 for the additional 1 kW. Further dividing this into a daily cost equates to $0.38/kW/day.	$0.38/kW/day (based on average metered demand)

For the irrigation category, our cost reflective pricing approaches do not meet the target revenue requirement and we apply residual charges for the balance. The aim with residual charges is that structures should share costs in a fair and equitable way, and not influence customer behaviour.

With the limited additional residual charge, and the limited ability for the customer to respond inefficiently, the pump motor nameplate also provides a suitable (and simple) mechanism for applying residual charges.

Industrial supplies

The table below sets out the cost reflective price components and target prices for connections in the industrial category.

Cost reflective price components	*Target price*
Booked capacity As with general supplies, a key determinant of cost is the capacity that each customer requests us to provide and reserve for their use. Industrial customers usually have a dedicated distribution transformer, associated switchgear and some high voltage cables that are sized for their capacity requirements. These assets amount to 30% of the overall assets allocated to the category, equating to annual costs of $604k for a combined capacity of 23.1 MVA. On a per kVA basis, this supports a cost-reflective price of $26.2/kVA per year.	The average cost of localised assets per kVA of booked capacity is $26.2/kVA per year.
Transmission charges – Benefit based charges and residual charges The same circumstances noted for irrigation supplies applies.	Reflecting benefit based charges supports a volume-based price of 0.30c/kWh Reflecting residual charges supports an average demand price of $0.38/kW/day

For the industrial category, our cost reflective pricing approaches do not meet the target revenue requirement, and we apply residual charges for the balance. The aim with residual charges is that structures should share costs in a fair and equitable way and not influence customer behaviour.

Residual charge structures	*Structure*
Fixed charges Fixed daily charges are non-distortionary but they tend not to provide an equitable basis for sharing costs where they are not linked to the capacity of each connection. To align with the General Supply category (and maintain the link to capacity established through that approach) it is appropriate to apply a fixed daily charge that is consistent with the progression established by those categories. This helps address step changes in charges as customers migrate between the General Supply and Industrial categories. Scaling up the charge for the 300 kVA category to a representative 345 kVA supports a daily fixed price of $16 per day.	Fixed daily charge per connection
Capacity charges Consistent with our approach for the irrigation category, with the limited additional residual charge, and the limited ability for the customer to respond inefficiently, the booked capacity also provides a suitable (and simple) mechanism for applying residual charges.	$/kVA based on booked capacity

Large users and generation

With our other charge categories, it is important to establish cost reflective pricing components so that incentives are expressed to customers via the price (and so that customers within each category pay an amount that reflects their cost impacts). The large user and generation categories are different. For these categories our connection specific cost allocation establishes a charge that reflects our cost. The mechanism by which this charge is passed on in respect of each connection must simply ensure that the correct amount is recovered.

To ensure that the customer sees cost reflective incentives, we explain the cost allocation in our notification of pricing updates.

7.8. Setting prices

The sections above establish target revenues, target cost reflective prices, and suitable price structures for collecting the balance of revenue.

We use this framework to set prices taking account of our pricing strategy, sustainability and decarbonisation goals, customer preferences, equity and fairness, vulnerable customers and regulatory considerations set out in section 3. This calculation incorporates our forecast of chargeable quantities.

The resulting forecast revenue varies slightly from the target cost allocation slightly because we must round prices (in this case, to 4 decimal places).

General Supply

We begin the assessment with the 20kVA category because it must comply with the low fixed charge regulations, which restricts the amount that we can apply as a fixed charge, and therefore influences the volume-based prices that we must set to recover the balance of revenue.

Starting with transmission charges, we first set a flat volume-based price reflecting the residual charge. The link to volume-based pricing for benefit-based charges is less clear, and we have elected to follow the Electricity Authority's guidance and recover this within the fixed daily component. The fixed component is set to match the balance of the revenue requirement.

For distribution prices, the target cost reflective price for local assets is $34.5/kVA/year. Applying this to the average fused capacity within each subcategory provides a target daily price:

	8 kVA	20 kVA	50 kVA	69 kVA	100 kVA	150 kVA	300 kVA
Target daily charge ($/day)	0.73	1.56	4.02	6.16	10.00	14.37	24.20

While we expect to transition toward these target charge levels over the next few years, for the 20 kVA category we are limited by regulation to charge no more than 90c/day (which must also cover transmission costs). This limit forces us to apply higher volume prices, which in turn affects the other subcategories, and we must lower their daily charges to avoid over-recovery. With residential customers spread across the 8kVA, 20kVA and 50kVA categories, we apply a similar balance between fixed and volume-based prices to avoid creating a disconnect at the boundary between the categories.

For FY27, we have decoupled the 69kVA+ categories from the volume prices set for the 20kVA category. This allows us to align more closely with the target capacity charges above and set lower volume prices.

The target cost reflective price for upstream assets is 6.7c/kWh for volumes used during weekdays (Mon to Fri, 7am to 9pm). Volume prices also recover the balance of the revenue requirement, so we interpret the 6.7c/kWh as a target differential between day vs night and weekend pricing (acknowledging that it's applied throughout the year, rather than seasonally). The remaining volume-price options are set to provide appropriate incentives in relation to the anytime and day vs night and weekend prices.

For FY27 we are required to price the majority of our volumes that are metered and charged to customers as "anytime" volume using time-varying prices (ie our day, night and weekend prices). There are various mechanisms through which this can be avoided, so to address the arbitrage incentive we have set the default anytime price to the peak price. We expect use of the anytime price to largely be eliminated with this approach.

The unmetered lighting service is being phased out. During this phase-out the streetlighting price is set to the same price established for the streetlighting category, and other prices have been incremented with the movement in CPI (the latter includes maintenance of the fixture itself).

This leads to the following prices and revenues:

General Supply 20 kVA	**Forecast quantity**		**Price**		**Revenue ($000)**
Fixed charge	16,367.3	Connections	0.9000	$/Con/day	5,376.7
Day of DNW	44,481.1	MWh	0.1080	$/kWh	4,804.0
Night & Weekend of DNW	48,751.7	MWh	0.0452	$/kWh	2,203.6
Controlled 16h supply	28,824.4	MWh	0.0514	$/kWh	1,481.6
Night boost supply	614.7	MWh	0.0474	$/kWh	29.1
Night only supply	2,490.6	MWh	0.0372	$/kWh	92.7
Anytime supply	3,468.7	MWh	0.1080	$/kWh	374.6
Unmetered streetlighting	9.0	Fixtures	0.2023	$/fixture/day	0.7
Unmetered floodlighting	2.0	Fixtures	0.3888	$/fixture/day	0.3
Unmetered verandah lighting	10.2	Fixtures	0.3423	$/fixture/day	1.2
Total					**14,353.7**
Target					14,364.4

For the 8kVA and 50kVA General Supply subcategories the volume prices are tied to the prices we set for the GS20 category above. For these subcategories we adjust the fixed charge to match the revenue requirement. This results in the following prices and revenues:

General Supply 8 kVA	**Forecast quantity**		**Price**		**Revenue ($000)**
Fixed charge	445.3	Connections	0.4000	$/Con/day	65.0
Day of DNW	1,219.0	MWh	0.1080	$/kWh	131.7
Night & Weekend of DNW	376.2	MWh	0.0452	$/kWh	17.0
Controlled 16h supply	196.9	MWh	0.0514	$/kWh	10.1
Night boost supply	0.0	MWh	0.0474	$/kWh	0.0
Night only supply	15.3	MWh	0.0372	$/kWh	0.6
Anytime supply	176.6	MWh	0.1080	$/kWh	19.1
Unmetered streetlighting	0.0	Fixtures	0.2023	$/fixture/day	0.0
Unmetered floodlighting	0.0	Fixtures	0.3888	$/fixture/day	0.0
Unmetered verandah lighting	0.0	Fixtures	0.3423	$/fixture/day	0.0
Total					**243.4**
Target					243.4

General Supply 50 kVA	Forecast quantity		Price		Revenue ($000)
Fixed charge	1,845.7	Connections	2.2747	$/Con/day	1,532.4
Day of DNW	12,243.6	MWh	0.1080	$/kWh	1,322.3
Night & Weekend of DNW	13,191.9	MWh	0.0452	$/kWh	596.3
Controlled 16h supply	1,671.3	MWh	0.0514	$/kWh	85.9
Night boost supply	132.7	MWh	0.0474	$/kWh	6.3
Night only supply	280.3	MWh	0.0372	$/kWh	10.4
Anytime supply	1,600.7	MWh	0.1080	$/kWh	172.9
Unmetered streetlighting	0.0	Fixtures	0.2023	$/fixture/day	0.0
Unmetered floodlighting	0.0	Fixtures	0.3888	$/fixture/day	0.0
Unmetered verandah lighting	1.0	Fixtures	0.3423	$/fixture/day	0.1
Total					**3,723.8**
Target					3,726.6

For our larger general sub-categories we align the capacity charging more closely with the cost reflective targets, allowing us to set much lower (and simplified) volume pricing. For larger supplies, an individual load response usually results in unused network capacity, rather than increase diversification, so the efficiencies of an untargeted load response are less clear. On this basis we adopt a flat volume price approach for all load.

General Supply 69 kVA	Forecast quantity		Price		Revenue ($000)
Fixed charge	363.8	Connections	7.9126	$/Con/day	1,050.7
Anytime supply	20,090.2	MWh	0.0616	$/kWh	1,237.6
Unmetered streetlighting	0.0	Fixtures	0.2023	$/fixture/day	0.0
Unmetered floodlighting	0.0	Fixtures	0.3888	$/fixture/day	0.0
Unmetered verandah lighting	0.0	Fixtures	0.3423	$/fixture/day	0.0
Total					**2,288.2**
Target					2,288.5

General Supply 100 kVA	Forecast quantity		Price		Revenue ($000)
Fixed charge	468.6	Connections	12.9371	$/Con/day	2,212.8
Anytime supply	47,124.9	MWh	0.0616	$/kWh	2,902.9
Unmetered streetlighting	12.0	Fixtures	0.2023	$/fixture/day	0.9
Unmetered floodlighting	1.0	Fixtures	0.3888	$/fixture/day	0.1
Unmetered verandah lighting	0.0	Fixtures	0.3423	$/fixture/day	0.0
Total					**5,116.7**
Target					5,117.4

General Supply 150 kVA	Forecast quantity		Price		Revenue ($000)
Fixed charge	211.0	Connections	16.9968	$/Con/day	1,309.0
Anytime supply	25,285.1	MWh	0.0616	$/kWh	1,557.6
Unmetered streetlighting	0.0	Fixtures	0.2023	$/fixture/day	0.0
Unmetered floodlighting	0.0	Fixtures	0.3888	$/fixture/day	0.0
Unmetered verandah lighting	0.0	Fixtures	0.3423	$/fixture/day	0.0
Total					**2,866.6**
Target					2,866.9

General Supply 300 kVA	Forecast quantity		Price		Revenue ($000)
Fixed charge	108.0	Connections	23.3653	$/Con/day	921.1
Anytime supply	15,290.5	MWh	0.0616	$/kWh	941.9
Unmetered streetlighting	0.0	Fixtures	0.2023	$/fixture/day	0.0
Unmetered floodlighting	0.0	Fixtures	0.3888	$/fixture/day	0.0
Unmetered verandah lighting	0.0	Fixtures	0.3423	$/fixture/day	0.0
Total					**1,863.0**
Target					1,863.2

Irrigation

For the residual component of transmission charges we are progressively aligning with the target cost reflective price of $0.38/kW/day based on average demand. This year we have set the price to $0.288/kW/day with the balancing being applied through the traditional capacity charge. The link to average demand for benefit based charges is less clear, and this, together with the rest of the transmission charge allocation is recovered through the capacity charge.

For distribution charges we add a further cost reflective $87/kW per year for upstream assets (established in the previous section) to the transmission amount. This leaves a shortfall (for costs associated with localised assets and overheads), and we further adjust the price to match the total revenue requirement.

For those without harmonic mitigation (unfiltered), we maintain the relative differential for the distribution part of prices (leaving transmission the same), and for irrigation where we are recovering missed charges following a period of disconnection, we set the price at double the standard rate.

Irrigation	**Forecast quantity**		**Price**		**Revenue ($000)**
Irrigation capacity	146,194.5	kW	0.4856	S/kW/day	25,912.1
Irrigation unfiltered capacity	829.0	kW	0.6009	S/kW/day	181.8
Irrigation recovery capacity	54.5	kW	0.9710	S/kW/day	19.3
Average demand charge	21,956.6	kW	0.2880	S/kW/day	2,308.1
Anytime supply	192,340.2	MWh	0.0000	$/kWh	0.0
Total					**28,421.3**
Target					28,417.1

Industrial

For the residual component of transmission charges we are progressively aligning with the target cost reflective price of $0.38/kW/day based on average demand. This year we have set the price to $0.288/kW/day with the balancing being applied through the traditional booked capacity charge. The link to average demand for benefit based charges is less clear, and this, together with the rest of the transmission charge allocation is recovered through the booked capacity charge.

For distribution charges we first set a fixed daily charge. This charge has a proportionally greater impact for smaller connections in the category, and is set at the higher end of the fixed charges applied for the general connection category to avoid distortions at the boundary between the categories.

For the balance of distribution costs we add a further the cost reflective $26.2/kVA per year to the transmission component. This leaves a small shortfall, and we further adjust the price to match the total revenue requirement.

Finally, we adjust the price for the high voltage subcategory to exclude the cost of the distribution transformer, as these connections do not use this aspect of our service.

Industrial	**Forecast quantity**		**Price**		**Revenue ($000)**
Fixed charge	54.0	Connections	16.0000	$/Con/day	315.4
Booked capacity	22,320.0	kVA	0.2489	$/kVA/day	2,027.7
Booked capacity HV	750.0	kVA	0.2212	$/kVA/day	60.6
Booked capacity recovery	0.0	kVA	0.4979	$/kVA/day	0.0
Average demand charge	5,314.6	kW	0.2880	$/kW/day	558.7
Anytime supply	46,555.9	MWh	16.0000	$/kWh	315.4
Total					**2,962.3**
Target					2,962.6

Large Users

The revenue requirement is recovered using connection specific pricing. This approach ensures that the prices reflect costs. We still structure the pricing to match the smaller industrial category in order to provide a uniform approach, and also to explicitly record and reinforce the booked capacity – that is, the capacity that we maintain and reserve for each customer's use.

This table shows the total chargeable quantities across all large users against the average price that we apply.

Large users	Forecast quantity		Price (average)		Revenue ($000)
Booked capacity	35,960.0	kVA	0.29510	$/kVA/day	3,873.4
Fixed charge	10.0	Connections	18.000	$/Con/day	65.7
Total					**3,939.1**
Target					3,939.3

Generation

As with large users, we are able to set connection specific prices that explicitly match costs. These customers are priced using an incremental cost approach, and the concept of a booked capacity is less meaningful for generation. Instead, we simply set a fixed daily charge for each connection.

Generation	Forecast quantity		Price (average)		Revenue ($000)
Fixed charge	7.493	Connections	430.8342	$/Con/day	1,178.3
Total					**1,178.3**
Target					1,178.3

Price components

The price components set out above are a combination of fixed (daily, capacity, demand based) charges and variable (volume based) charges. The following table summarises the proportion of revenue that we derive from fixed and variable charges for each connection category.

Prices are applied across a combination of fixed, capacity, and variable price components, depending on the connection category. The proportion of total revenue recovered, in aggregate, from each customer group using fixed and variable price components is shown here:

	8 kVA	**20 kVA**	**50 kVA**	**69 kVA**	**100 kVA**	**150 kVA**	**300 kVA**
Fixed charges	27%	37%	41%	46%	43%	46%	49%
Variable charges	73%	63%	59%	54%	57%	54%	51%

	Irrigation	**Industrial**	**Large Users**	**Generation**	**Street lighting**	**Total**
Fixed charges	100%	100%	100%	100%	95%	**73%**
Variable charges	0%	0%	0%	0%	5%	**27%**

Summary

The prices established above are set out in a consolidated schedule in appendix A. This schedule also shows the proportion of each price that relates to transmission.

APPENDIX A – Alignment with Electricity Authority Pricing Principles

The information disclosure requirements require us to prepare and disclose a statement of the level of alignment with the Electricity Authority's pricing principles. We set this out below.

Alignment with Electricity Authority pricing principles

The Electricity Authority published Pricing Principles[1] that provide an approach for developing and assessing pricing methodologies for electricity distribution companies. After publishing the Pricing Principles, the Authority published a 'Practice Note' to help distributors interpret and apply the Pricing Principles. The Authority has also introduced a scorecard to evaluate distributors' pricing plans against the principles.

The Authority published a refreshed Practice Note[2] in December 2021 with an emphasis on expected timeframes for distribution pricing reform and what 'good looks like'. In October 2022 it issued a second edition setting out expectations for reform and pricing structures, as well as guidelines for passing through transmission charges.

The purpose of this section of our Pricing Methodology is to demonstrate how EA Networks' pricing approach is consistent – in our view and to the extent practicable – with the principles established by the Electricity Authority.

(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);

For each connection category we first allocate costs associated with any dedicated assets and then we additionally allocate a proportion of shared assets, plus a proportion of our overhead and residual costs. The addition of overhead and residual costs ensures that prices are greater than avoidable costs.

It also ensures that each connection category benefits from the presence of each other connection category, and that prices are less than standalone costs (that is, in the absence of the other connection categories, each connection category would pay an amount that represents standalone costs, and this would be more).

We also included a more detailed assessment of the subsidy free range which is set out in section 7.6. This assessment shows the relative position that each category sits, and highlights that our generation category sits slightly below the subsidy free range (as a result of contractual commitments).

Where expansion is required, we have previously funded this by way of capital contribution from the party driving that expansion.

[1] Distribution Pricing Principles, published by the Electricity Authority, June 2019.
[2] https://www.ea.govt.nz/documents/299/Distribution_pricing_practice_note.pdf

For example, if we are required to extend our existing overhead network to connect to a new dairy farm installation (say 700 metres for the single connection), the farmer will be charged the full incremental cost of extending the network to connect the property.

By charging customers directly for the incremental works we ensure that there are no subsidies within the pricing (where incremental costs can be directly attributed). The Authority's practice note suggests that this approach means that the new connection will have "no bearing on pricing to the wider network". We observe that this is not the case. While the new network might be outside the RAB, we must still manage, operate, maintain, and replace the assets, and these costs are recovered through pricing.

Moving forward, we anticipate shifting to a connection contribution basis where we assess the net present value of all expected costs and revenues, and align the upfront charge with the difference between those two assessments. This approach also ensures that new customers come "on board" on an equal footing to existing customers, ensuring that no cross-subsidy occurs.

An exception to this principle has occurred where EA Networks is contractually bound to a connection agreement for a generating customer that was put in place prior to the pricing principles. That agreement specifies charges that, while they have been indexed, now fall below the avoidable costs of the incremental assets required for that connection.

(ii) REFLECTING THE IMPACTS OF NETWORK USE ON ECONOMIC COSTS;

Our methodology identifies pricing structures and associated price levels that reflect the economic cost of using the network. To the extent possible, we adopt those pricing structures and price levels when setting prices.

The key assessments of price structures that align with economic costs are set out in section 7.7. For the General Supply category we identified capacity and contribution to coincident peak demand as the most relevant drivers of our costs, and energy volume as the prime driver of transmission costs. For the Industrial category and the Irrigation category, where there is much less diversity between usage, we identified installed capacity and booked (reserved) capacity, as well as average demand as the key drivers of costs.

When setting prices, we first assess and set prices at the level that reflects the cost identified. In several situations we are unable to match the economic cost driver - the main exceptions being:

- For our GS20 category we are limited by the low fixed charge regulations. The regulations require us to provide a low fixed charge option for residential customers of no more than 90c/day (and consequently we must apply higher volume prices to meet the target revenue requirement).

  We could separate business supplies into a separate category and apply higher fixed charge. However, this would require an entirely separate category, associated cost allocation and a full set of volume prices. It is increasing difficult to define and distinguish business and residential customer activities which we observe leads to conflict with customers. Also, we are not observing any significant degree of distortion from the higher volume prices for these customers. Small commercial customers do not tend to be the ones installing photovoltaics.

We could separate off higher consumption residential customer (>9000 kWh/year) and apply a higher fixed charge. We have looked at this, and the associated costs carefully. In the absence of this split, customers have an artificially high volume price incentive to reduce consumption or install photovoltaics. If we instead applied a higher fixed price, we would simply provide a fixed charge incentive to install photovoltaics to get below the 9000 kWh/year level. We'd be incurring cost and complexity to replace one incentive with another.

- For our larger general sub-categories (GS69 to G300), we have decoupled the volume price from the level set for smaller general sub-categories and we are progressively moving toward capacity based charging.

(iii) *REFLECTING DIFFERENCES IN NETWORK SERVICE PROVIDED TO (OR BY) CONSUMERS;*

We aim to provide options for customers to select the level of network services provided. For the General Supply category, customers have a choice of the supply capacity they require (with higher charges for higher capacity). In recent years we added 69 kVA and 300 kVA subcategories to further refine the options for customer. Customers also have options for volume-based pricing, where we provide lower price options for off peak usage, or usage that we can control.

For the Irrigation and Industrial categories, we link charges to the capacity that the customer selects. Customers with higher capacity needs pay more. Two years ago we added an industrial subcategory for new tech connections that provide their own low voltage transformation (rather than using our transformers) to better reflect the reduced level of service provided with a lower price.

For Large Users and Generation connections we allow the customer to specify the attributes and capacity of the supply, the level of back up services that are available, and the level of security. The actual costs are then reflected in our cost allocation.

(iv) *ENCOURAGING EFFICIENT NETWORK ALTERNATIVES.*

We set our prices to encourage efficient network alternatives. Customers in the General Supply category are encouraged to opt for demand response supply through our controlled and off-peak load prices. The lower price encourages customers to consider network alternatives, such as thermal storage water heaters that heat over night but meet hot water demand during peak times (that is, an alternative to us providing additional peak network capacity).

The same pricing provides options for customers with solar generation, batteries, and energy management capability.

This year we introduced credits for energy export in situations where the align with the timing and location of network peaks that drive investment. These credits are intended to broadly reflect the longer-term average cost of adding capacity, and to the extent possible, provide a stable signal and reward for generation that operates to support our service.

(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.

In section 7.7 we identify approaches that are suitable (and note those that are unsuitable) to use as pricing options that least distort network usage. There is no pricing approach that does not have some degree of distorting influence, but some approaches produce more distortion than others.

For the General Supply category we determined that a combination of capacity and relatively low volume pricing would be the least distorting. For the irrigation category, loading the small additional amount against the pump capacity is unlikely to noticeably distort behaviour. For the Industrial category, splitting the recovery between a fixed charge and an additional booked capacity charge minimises distortion.

We expect further development in this area. An emerging theme is that spreading the recovery across multiple pricing approaches tends to provide the least distortion, because each approach, in itself, may not be enough to influence customer behaviour. We must balance this against the complexity that multiple charging approaches brings with it.

(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 offer non-standard approaches for Large Users who have specific network connection and operation requirements to appropriately reflect the economic value to them of the network service. For standard consumers, we set prices to be less than the standalone cost of supply.

We regularly engage with consumers to test price/quality preferences via surveys and direct interaction. We also enable consumers to make price/quality trade-offs by offering controlled and uncontrolled prices in addition to incentives to change capacity (if possible).

Connections in the General Supply category are encouraged to opt for demand response supply through our controlled load and off-peak prices. These options provide a reduced price compared to the uncontrolled variable price and aim to reflect the value of load management.

In recent years we added 69 kVA and 300 kVA subcategories to provide further choice for customers to refine and “right-size” their capacity requirements. We have also added an Industrial Supply subcategory for new technology that is able to connect at high voltage using less of our system. This new subcategory recognises savings with a lower price.

(d) DEVELOPMENT OF PRICES SHOULD BE TRANSPARENT AND HAVE REGARD TO TRANSACTION COSTS, CONSUMER IMPACTS, AND UPTAKE INCENTIVES.

We aim to make sure our prices are developed in a transparent way. We publish this Pricing Methodology and provide information on our website on the connection categories, prices, and related statistical information.

When we change prices, we do so with due regard to the impact on stakeholders of any changes in prices and/or transaction costs. Consumers have a reasonable expectation that our prices will be stable and will not shift significantly over time. Changes to our prices have been, and will continue to be, consistent with the limits placed on us under the DPP Determination by the Commerce Commission.

We manage the transaction costs on retailers by consulting with them in advance, and discussing pricing with other distributors to help with standardisation of pricing, thereby reducing transaction costs for retailers and consumers.

We have endeavoured to minimise transactions costs as well as processing costs incurred by retailers by maintaining a simple and concise price portfolio. Whilst balancing the needs of end user customers and their specific pricing requirements, our portfolio of prices extends to only six connection categories and 38 specific prices. Changes to this are limited and only made when necessary for new customers or for changes to the business. Over the last two years we have rationalised the subcategories in our irrigation and industrial categories to reflect our updated cost drivers, and we have amalgamated volume price categories where the underlying prices are the same (that is, in situations where we are applying nil prices). Offsetting this rationalisation, new regulations require us to consider area-based export credits, and when coupled with regulations relating to price category codes, we must create separate categories and replicate pricing structures across those categories. This has substantially increased the number of categories and tariffs we must maintain, adding significant complexity.

Our Default Distributor Agreement is standard. We have not negotiated alternative (nor preferential) terms with any retailer. All retailers face the same set of prices and terms, and we undertake transparent group consultation when proposing changes.

APPENDIX B – Alignment with Commerce Commission Information Disclosure

This appendix sets out the disclosure requirements and provides a reference to the relevant information in this pricing methodology.

Information Disclosure Requirement	Reference in this document
2.4.1 Every EDB must publicly disclose, before the start of each disclosure year, a pricing methodology which-	This Pricing Methodology is publicly disclosed before the end of March each year for prices that apply from 1st April the same year.
(1) Describes the methodology, in accordance with clause 2.4.3 below, used to calculate the prices payable or to be payable;	See Information Disclosure 2.4.3 below.
(2) Describes any changes in prices and target revenues;	Section 2.1 provides a summary of the overall movement in prices, section 2.3 describes the impact of changes in price structure, and section 7.1 shows changes in target revenue. Appendix C shows new prices alongside previous prices.
(3) Explains, in accordance with clause 2.4.5 below, the approach taken with respect to pricing in non-standard contracts and distributed generation (if any);	Our non-standard contracts are set out in section 7.7. Our credits for export and methodology for setting those credits is explained in section 7.2
(4) Explains whether, and if so how, the EDB has sought the views of consumers, including their expectations in terms of price and quality, and reflected those views in calculating the prices payable or to be payable. If the EDB has not sought the views of consumers, the reasons for not doing so must be disclosed.	Section 4.4 sets out high we have sought customers' views, summaries what those views are, and how we have incorporated them within our pricing.
2.4.2 Any change in the pricing methodology or adoption of a different pricing methodology, must be publicly disclosed at least 20 working days before prices determined in accordance with the change or the different pricing methodology take effect.	This pricing methodology is different to the previous methodology, and it is publicly disclosed by 4 March 2026 to comply with this requirement.
2.4.3 Every disclosure under clause 2.4.1 above must-	
(1) Include sufficient information and commentary to enable interested persons to understand how prices were set for each consumer group, including the assumptions and statistics used to determine prices for each consumer group;	We provide an overview of the pricing methodology steps in section 6, and then detail the application of those steps for each connection category in section 7. The statistics for each connection category that are used in the methodology are set out in section 7.3.

Information Disclosure Requirement	Reference in this document
(2) Demonstrate the extent to which the pricing methodology is consistent with the pricing principles and explain the reasons for any inconsistency between the pricing methodology and the pricing principles;	Appendix A provides an assessment of the alignment with the pricing principles and provides (or references) the reasons for areas of inconsistency.
(3) State the target revenue expected to be collected for the disclosure year to which the pricing methodology applies;	Target revenue is set out in section 7.1.
(4) Where applicable, identify the key components of target revenue required to cover the costs and return on investment associated with the EDB's provision of electricity lines services. Disclosure must include the numerical value of each of the components;	All components of target revenue are set out in section 7.1.
(5) State the consumer groups for whom prices have been set, and describe– (a) the rationale for grouping consumers in this way; (b) the method and the criteria used by the EDB to allocate consumers to each of the consumer groups;	The connection categories, the rationale for each category, and the criteria for allocation is set out in section 7.3.
(6) If prices have changed from prices disclosed for the immediately preceding disclosure year, explain the reasons for changes, and quantify the difference in respect of each of those reasons;	Section 2.2 provides the drivers of our price movements and quantifies each aspect.
(7) Where applicable, describe the method used by the EDB to allocate the target revenue among consumer groups, including the numerical values of the target revenue allocated to each consumer group, and the rationale for allocating it in this way.	Section 7.4 details our approach for assigning assets to each connection category, and then section 7.5 considerers each cost, in turn, explaining the method and rationale for the method, as well as detailing the resulting allocation.
(8) State the proportion of target revenue (if applicable) that is collected through each price component as publicly disclosed under clause 2.4.18.	Section 7.8 shows the proportion (by way of the actual amount) of target revenue that is collected from each price component, for each connection category in turn.
2.4.4 Every disclosure under clause 2.4.1 above must, if the EDB has a pricing strategy-	

Information Disclosure Requirement	Reference in this document
(1) Explain the pricing strategy for the next 5 disclosure years (or as close to 5 years as the pricing strategy allows), including the current disclosure year for which prices are set;	Section 5 sets out our pricing strategy, the changes we are implementing in the current year, and the changes we expect to implement over the coming 5 years.
(2) Explain how and why prices for each consumer group are expected to change as a result of the pricing strategy;	Section 2.4 also provides an indication of expected future price movements.
(3) If the pricing strategy has changed from the preceding disclosure year, identify the changes, and explain the reasons for the changes.	The table in section 5 details the anticipated changes and the reasons they are being contemplated. This is followed by an assessment of the impact on each connection category.
2.4.5 Every disclosure under clause 2.4.1 above must–	
(1) Describe the approach to setting prices for non-standard contracts, including– (a) the extent of non-standard contract use, including the number of ICPs represented by non-standard contracts and the value of target revenue expected to be collected from consumers subject to non-standard contracts;	Section 7.7 includes a sub-section detailing our non-standard contracts.
(b) how the EDB determines whether to use a non-standard contract, including any criteria used;	See above.
(c) any specific criteria or methodology used for determining prices for consumers subject to non-standard contracts and the extent to which these criteria or that methodology are consistent with the pricing principles;	See above.
(2) Describe the EDB's obligations and responsibilities (if any) to consumers subject to non-standard contracts in the event that the supply of electricity lines services to the consumer is interrupted. This description must explain— (a) the extent of the differences in the relevant terms between standard contracts and non-standard contracts;	See above. Generation customers tend to have a value of lost load that matches the energy price. In this situation it is more efficient to operate a single supply solution, avoiding the cost of back-up assets, and accepting the occasional outages that will occur. These customers face the cost of actual assets employed, so benefit from the savings that this approach provides.

Information Disclosure Requirement	Reference in this document
(b) any implications of this approach for determining prices for consumers subject to non-standard contracts;	
(3) Describe the EDB's approach to developing prices for electricity distribution services provided to consumers that own distributed generation, including any payments made by the EDB to the owner of any distributed generation, and including the— (a) prices; and (b) value, structure and rationale for any payments to the owner of the distributed generation.	We maintain a specific generation connection category and the allocation of costs is detailed in section 7.5, and the determination of prices is detailed in section 7.8. Individual prices are shown in Appendix C. Our credits for export and methodology for setting those credits is explained in section 7.2
2.4.6 Every EDB must at all times publicly disclose a description of its current policy or methodology for determining capital contributions, including-	Section 7.7 has a sub-section covering our capital contribution policy and its link with pricing. The policy itself is available at https://www.eanetworks.co.nz/about-us/disclosures
1(a) the circumstances (or how to determine the circumstances) under which the EDB may require a capital contribution;	See above, and section 4.2 to 4.7 of the referenced policy.
1(b) how the amount payable of any capital contribution is determined. Disclosure must include a description of how the costs of any assets (if applicable), including any shared assets and any sole use assets that are included in the amount of the capital contribution, are calculated;	See above, and section 4.2 to 4.7 and schedule A of the referenced policy.
1(c) the extent to which any policy or methodology applied is consistent with the relevant pricing principles;	See above.
2) A statement of whether a person can use an independent contractor to undertake some or all of the work covered by the capital contribution sought by the EDB	We generally undertake all customer driven network upgrades using our in-house contracting team, but accept upgrades by external contractors where these can be provided as part of customer-owned work that is being undertaken.
3) If the EDB has a standard schedule of capital contribution charges, the current version of that standard schedule	See New Connections and Extensions Policy document, Schedule A.

Information Disclosure Requirement	Reference in this document
	Refer: https://www.eanetworks.co.nz/about-us/disclosures
2.4.7 When a consumer or other person from whom the EDB seeks a capital contribution, queries the capital contribution charge, (and when the charge is not covered in the standard schedule of capital contribution charges, or no such schedule exists) the EDB must, within 10 working days of receiving the request, provide reasonable explanation to any reasonable query from that consumer or other person of the components of that charge and how these were determined	Our process is to respond within the defined time for any query of such charges.

APPENDIX C – Pricing Schedule 2026-27

Electricity delivery price schedule for EA Networks

This schedule lists the prices that EA Networks uses to charge electricity retailers for the electricity delivery service in its Ashburton based network area. The delivery service includes the transmission and distribution of electricity to homes and businesses, but does not include the cost of the electricity itself.

Connection category	Price category code	Price category	Number of connections	Description	Delivery Prices (excl GST) 1 April 2025 to 31 March 2026	Delivery Prices (excl GST) From 1 April 2026	Unit of measure	Transmission Proportion
General	GS05	General Supply - 8 kVA	27.2	Capacity charge	0.3750	**0.4000**	$/con/day	13.7%
	GS05-RL	in rural load constrained area	297.9	Capacity charge	0.3750	**0.4000**	$/con/day	13.7%
	GS05-UA	in urban ashburton	120.2	Capacity charge	0.3750	**0.4000**	$/con/day	13.7%
	GS20	General Supply - 20 kVA	728.9	Capacity charge	0.7500	**0.9000**	$/con/day	14.4%
	GS20-RL	in rural load constrained area	7,733.4	Capacity charge	0.7500	**0.9000**	$/con/day	14.4%
	GS20-UA	in urban ashburton	7,905.1	Capacity charge	0.7500	**0.9000**	$/con/day	14.4%
	GS50	General Supply - 50 kVA	308.6	Capacity charge	1.7337	**2.2747**	$/con/day	10.9%
	GS50-RL	in rural load constrained area	1,058.7	Capacity charge	1.7337	**2.2747**	$/con/day	10.9%
	GS50-UA	in urban ashburton	478.4	Capacity charge	1.7337	**2.2747**	$/con/day	10.9%
		+ Volume charges		Day of DNW	0.1080	**0.1080**	$/kWh	14.1%
				Night & Weekend of DNW	0.0180	**0.0452**	$/kWh	33.6%
				Controlled 16h supply	0.0240	**0.0514**	$/kWh	29.6%
				Night boost supply	0.0240	**0.0474**	$/kWh	32.1%
				Night only supply	0.0180	**0.0372**	$/kWh	40.9%
				Anytime supply	0.0810	**0.1080**	$/kWh	14.1%
		+ Export credits		Anytime injection	0.0000	**0.0000**	$/kWh	0.0%
				Off-peak injection	NA	**0.0000**	$/kWh	0.0%
				Peak injection (RL categories only)	NA	**(0.0692)**	$/kWh	0.0%
				Peak injection (UA categories only)	NA	**(0.2310)**	$/kWh	0.0%
	GS69	General Supply - 69 kVA	363.8	Capacity charge	3.5027	**7.9126**	$/con/day	8.7%
	G100	General Supply - 100 kVA	468.6	Capacity charge	5.2830	**12.9371**	$/con/day	11.2%
	G150	General Supply - 150 kVA	211.0	Capacity charge	7.2858	**16.9968**	$/con/day	12.4%
	G300	General Supply - 300 kVA	108.0	Capacity charge	9.1780	**23.3653**	$/con/day	9.8%
		+ Volume charges		Anytime supply	0.0810	**0.0616**	$/kWh	24.7%
		+ Export credits		Anytime injection	0.0000	**0.0000**	$/kWh	0.0%
		+ Other charges		Unmetered street lighting	0.1949	**0.2023**	$/fixture/day	0.7%
				Unmetered floodlighting	0.3797	**0.3888**	$/fixture/day	0.0%
				Unmetered verandah lighting	0.3343	**0.3423**	$/fixture/day	0.0%
Irrigation	ISCH	Irrigation	1,618.6	Capacity charge	0.4998	**0.4856**	$/kW/day	15.8%
				Average demand charge	NA	**0.2880**	$/kW/day	100.0%
	ISCF	Irrigation unfiltered	8.0	Capacity charge	0.6185	**0.6009**	$/kW/day	12.7%
				Average demand charge	NA	**0.2880**	$/kW/day	100.0%
	ISCR	Irrigation recovery	0.7	Capacity charge	0.9998	**0.9710**	$/kW/day	15.7%
				Average demand charge	NA	**0.2880**	$/kW/day	100.0%
		+ Volume charges		Anytime supply	0.0000	**0.0000**	$/kWh	0.0%
		+ Export credits		Anytime injection	0.0000	**0.0000**	$/kWh	0.0%
Industrial	ICMD	Industrial	52.0	Fixed charge	12.0000	**16.0000**	$/con/day	0.0%
				Booked capacity charge	0.2878	**0.2489**	$/kVA/day	16.8%
				Average demand charge	NA	**0.2880**	$/kW/day	100.0%
	ICMH	Industrial high voltage	2.0	Fixed charge	12.0000	**16.0000**	$/con/day	0.0%
				Booked capacity charge	0.2647	**0.2212**	$/kVA/day	18.9%
				Average demand charge	NA	**0.2880**	$/kW/day	100.0%
	ICMR	Industrial recovery	0.0	Fixed charge	0.0000	**32.0000**	$/con/day	0.0%
				Booked capacity charge	0.0000	**0.4979**	$/kVA/day	16.8%
				Average demand charge	NA	**0.2880**	$/kW/day	100.0%
		+ Volume charges		Anytime supply	0.0000	**0.0000**	$/kWh	0.0%
		+ Export credits		Anytime injection	0.0000	**0.0000**	$/kWh	0.0%
Large Users	LUCM	ANZCO Seafield	2.0	Fixed charge	18.0000	**20.0000**	$/con/day	0.0%
				Booked capacity charge	0.3436	**0.4437**	$/kVA/day	54.1%
	LUPP	Talley's Fairfield 11kV	1.0	Fixed charge	18.0000	**20.0000**	$/con/day	0.0%
				Booked capacity charge	0.1128	**0.1408**	$/kVA/day	68.3%
	LUP2	Talley's Ashburton	1.0	Fixed charge	18.0000	**20.0000**	$/con/day	0.0%
				Booked capacity charge	0.4230	**0.5396**	$/kVA/day	50.0%
	LUP3	Talley's Fairfield 22kV	1.0	Fixed charge	18.0000	**20.0000**	$/con/day	0.0%
				Booked capacity charge	0.0416	**0.0519**	$/kVA/day	42.6%
	LUMH	Mt Hutt Ski Area	1.0	Fixed charge	18.0000	**20.0000**	$/con/day	0.0%
				Booked capacity charge	0.2644	**0.3449**	$/kVA/day	15.5%
	LUHP	Highbank Pumps	1.0	Fixed charge	18.0000	**20.0000**	$/con/day	0.0%
				Booked capacity charge	0.1400	**0.1501**	$/kVA/day	55.5%
	LURX	Marley	2.0	Fixed charge	18.0000	**20.0000**	$/con/day	0.0%
				Booked capacity charge	0.1932	**0.2136**	$/kVA/day	33.7%
		+ Volume charges		Anytime supply	0.0000	**0.0000**	$/kWh	0.0%
		+ Export credits		Anytime injection	0.0000	**0.0000**	$/kWh	0.0%
Generation	LUHB	Highbank hydro	1.0	Fixed charge	1,618.4859	**1,618.4859**	$/con/day	0.1%
	LUMO	Montalto hydro	1.0	Fixed charge	60.2740	**60.2740**	$/con/day	0.2%
	LUCD	Cleardale hydro	1.0	Fixed charge	105.4928	**107.5069**	$/con/day	1.9%
	LULN	Lavington hydro	1.0	Fixed charge	25.2250	**25.3484**	$/con/day	0.9%
	LURD	Lauriston solar farm	1.0	Fixed charge	1,077.4746	**1,218.7906**	$/con/day	86.1%
	LUGL	Gartartan solar farm #1	1.0	Fixed charge	1.3438	**3.4845**	$/con/day	20.2%
	LUGT	Gartartan solar farm #2	1.0	Fixed charge	7.8104	**12.6286**	$/con/day	11.3%
	LUNF	Fairton solar farm	1.0	Fixed charge	0.0000	**21.4776**	$/con/day	15.9%
	LUSO	Somerton solar farm	0.3	Fixed charge	0.0000	**393.8853**	$/con/day	80.4%
	LUFR	Fords Road solar farm #1	0.2	Fixed charge	0.0000	**183.9442**	$/con/day	1.3%
		+ Volume charges		Anytime supply	0.0000	**0.0000**	$/kWh	0.0%
		+ Export credits		Anytime injection	0.0000	**0.0000**	$/kWh	0.0%
Street lighting	MCSL	Street Lighting	8.0	Unmetered street lighting	0.1949	**0.2023**	$/fixture/day	0.7%
				Anytime supply	0.0000	**0.0152**	$/kWh	100.0%
Miscellaneous	NOCH	No charge, or charged elsewhere	3.0	Fixed charge	0.0000	**0.0000**	$/con/day	0.0%

APPENDIX D – Directors' certification

We, Paul Jason Munro and Andrew David Barlass, being directors of Electricity Ashburton Limited (EA Networks), certify that, having made all reasonable enquiry, to the best of our knowledge:

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

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	Andrew David Barlass

20 February 2026