Pricing Methodology
Electricity Distribution Network

Pursuant to the Electricity Distribution Information Disclosure Determination 2012.

Effective from 1st April 2021

Contents

Definitions and common acronyms

Assets	The hardware, equipment or plant that is part of our electricity distribution network.
ACOT	Avoided Cost of Transmission.
Controlled Energy	Electricity supply for which we temporarily cease supply when required, typically during periods of high load. It is most commonly water heating load.
Customer	An end user who is connected to the electricity distribution network.
Customer Load Groups	The customer segments that have similar electricity requirements and that share similar pricing methodologies.
GXP	Grid Exit Point. This is the point where EA Networks' electricity distribution network connects to Transpower's transmission network.
ICP	Installation Control Point. This is the isolation point where a customer connects to the distribution network and where the retailers metering is located.
kW	Kilowatt. The measure of electrical capacity.
kWh	Kilowatt-hour. The measure of electricity consumption by which retail electricity consumption is measured.
kVA	Kilovolt Ampere. A unit of measure for how much power is being provided through a business or home's electrical circuits or technology.
Retailer	The entity that charges customers for their electricity usage.
RCPD	Regional Coincident Peak Demand. This affects the way that Transpower allocates interconnection cost.
Target Revenue	The forecasted annual revenue we expect to earn as determined under the Default Price Path rules and guidelines.
Transmission costs	Transmission costs are comprised of charges directly from Transpower, Avoidable Cost of Transmission paid to Generators (now ceased), and recoverable costs including regulatory levies and local authority rates.
WACC	Weighted Average Cost of Capital. This is the measure of the return an Electricity Distribution company may achieve under the Default Price Path regulations set by the Commerce Commission.

Introduction

Purpose

The purpose of this document is to detail how EA Networks develops the prices it charges for connection to, and use of, the network.

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. Three distribution lines run into up-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.

There are four hydro generating stations embedded in the network. Barrhill is 0.5MW, Cleardale is a 1MW station, Montalto is a 1.6MW station and Highbank is a 28MW station.

Summary of current revenue and pricing

We have reviewed our pricing against the Commerce Commission's (Commission) Default Price Path (DPP) requirements. The pricing approach is broadly in-line with previous years.

Gross prices will fall on average for 2021-22 compared to 2020-21 due to a reduction in the target revenue we expect to recover from prices (before accounting for the 2021 refund of over-recovered revenue).

Explanation of the 2021 refund of over-recovered revenue

Target revenue for the 2020-21 pricing year was set at the original forecast allowable revenue amount of $46.7 million. During January 2021, the Commerce Commission identified an omission in the calculation of forecast revenue for 2020-21. Upon review by EA Networks, a second omission in the calculation of forecast revenue for 2020-21 was identified that combined to a total of $3.3 million, resulting in target revenue being set too high for 2020-21.

EA Networks undertook to refund customers for the over-recovery in 2020-21, via a discount payment, totalling approximately $3.5 million at the culmination of the 2021 financial year (during April 2021). This one-off payment reduces actual revenue from prices for the 2020-21 pricing year.

This pricing methodology uses the originally forecast/target revenue of $46.7 million for comparisons and commentary (since that forecast/target cannot be changed retrospectively). However, readers should be clear that forecast/target revenue for 2020-21 should have been $43.4 million.

Target revenue for 2021-22

Target revenue for 2021-22 is $41.2 million, representing an 11.4% reduction from $46.4 million in 2020-21. The target revenue for 2021-22 is set to recover:

- $33.1 million for delivering Distribution services, representing a $0.08 million or 0.2% increase from 2020-21
- $8.1 million for pass-through and Transmission costs, representing a $5.4 million or 39.7% reduction from 2020-21. The reduction is mostly due to a $5.3 million or 40.8% reduction to transmission costs compared to 2020-21.

The Forecast revenue from prices is set to recover 0.13% less than the Forecast allowed revenue for 2021-22 of $41.3 million, with $33.1 million for Distribution services and $8.1 million for pass-through and Transmission costs.

More detail on the change to target revenue for 2021-22 compared to 2020-21 is shown here:

Target revenue, $000	2021-22	2020-21	$ change	% change
Distribution services	$33,052	$32,975	$77	0.2%
Pass-through and Transmission Costs				
Rates and Levies	$379	$409	-$31	-7.5%
Transmission	$7,736	$13,057	-$5,322	-40.8%
Sub-total	$8,114	$13,467	-$5,352	-39.7%
Target Revenue	**$41,166**	**$46,442**	**-$5,276**	**-11.4**
New connections revenue	$102	$224	-$122	-54.5%
Forecast revenue from Prices	**$41,268**	**$46,666**	**-$5,398**	**-11.6%**

Target revenue does not include new connection revenue because it is recovered directly from customers with new connections, not through standard prices. Forecast new connection revenue for 2021-22 is $102,000.

Including forecast new connection revenue, Total Forecast Revenue from Prices for 2021-22 is $41.3 million, an 11.6% reduction from 2020/21 Forecast Revenue from Prices.

Average change in prices for 2021-22

Prices for each customer load group, in aggregate, will on average reduce for 2021-22 by 13.1% compared to 2020-21 due to the reduction to target revenue. The average aggregate change for each customer load group is shown here:

Customer load group	Average change %
General	-8.7%
Irrigation	-16.7%
Industrial	-14.7%
Large Users	-24.8%
Generation	-2.3%
Average change – all groups	**-13.1%**

Note: Large user customer load group includes Streetlighting.

Summary of revenue and cost

The following tables provide an overview of our revenue recovery by customer type, as well as a breakdown of major cost types and more detail on recoverable pass-through costs.

Target Revenues by Customer Load Group

This table shows how total Target Revenue for 2021/22 is recovered by customer load group.

Customer load group	Connections	Target revenue ($000)
General	18,138	$19,274
Irrigation	1,614	$18,410
Industrial	44	$1,747
Large Users	13	$1,326
Generation	4	$0.408
Total	**19,813**	**$41,166**

Target Revenues by Cost Category

This table shows the main costs making up the Target revenue for 2021-22.

Cost category	Target revenue ($000)
Distribution services	
Operations & maintenance	$7,972
Administration	$5,086
Depreciation	$10,419
Cost of capital	$9,575
Subtotal	**$33,052**
Pass-through costs	
Rates & levies	$0.379
Transmission	
Transmission – connection	$1,053
***Transmission** – interconnection*	$6,682
Transmission – subtotal	$7,735
Subtotal	**$8,114**
Target revenue	**$41,166**

Pass-through costs are actual costs. No cost of capital or margin is recovered.

For 2021-22, the *Transmission – interconnection cost* includes a $2.4 million early repayment of a Transpower New Investment Contract. This follows recovery of a $5.2 million early repayment in 2020-21. The early repayments are designed to reduce material year-to-year volatility in transmission – interconnection costs caused by the current transmission pricing methodology (TPM). The year-to-year volatility was adversely affecting customers, particularly in the Irrigation customer load group. The volatility in transmission costs is expected to cease with introduction of the proposed new TPM.

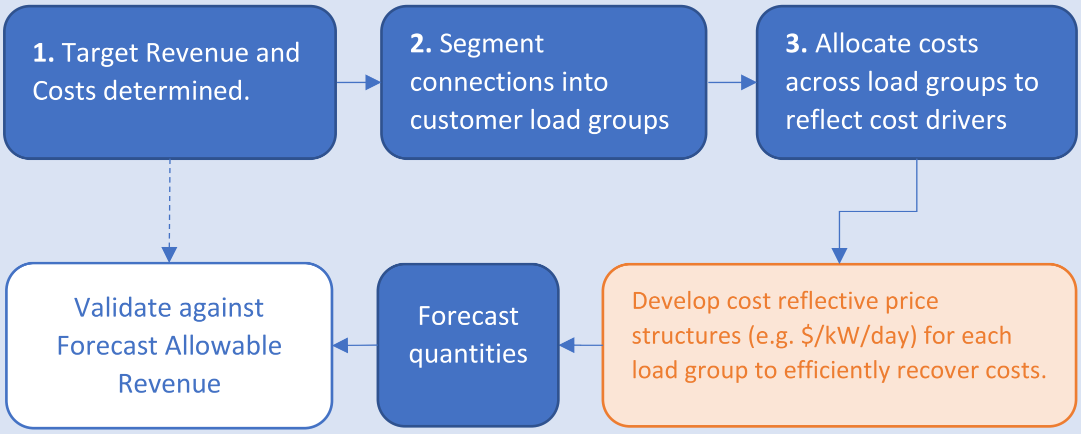
Overview of pricing methodology

EA Networks is an electricity distribution business (EDB). Our costs are largely fixed as we build and maintain long-life network assets. These assets are designed to enable the delivery of electricity to connected customers (current and future) in the Mid Canterbury region.

We recover our costs through prices charged (via electricity Retailers) to customers that are connected to the electricity network. Where possible, we aim to provide a fixed price signal reflecting the cost to deliver capacity to customers, albeit that a proportion of our revenue is recovered from variable price structures, largely due to regulations.

The prima facie strategy to develop prices is to reflect and recover as accurately as feasible the cost of providing network services to connected customers. In general terms, the greater the capacity (amount of energy) required by a customer, the greater the cost to provide network service to the customer. This is because the fixed cost of infrastructure required to provide more energy (more capacity) to a connection is higher. Consequently, network access prices increase in relation to capacity demanded, reflecting the higher cost to serve higher energy demands.

The development of our methodology and the prices that result is based on economic pricing principles given practical, physical, regulatory and commercial constraints. An overview of the price development process and pricing methodology is provided here:



Overview of Pricing Methodology

Costs are allocated based on segmentation of connected users. The purpose of these segmented types is to group individual customers into load groups that share similar electricity demand profiles and capacity requirements – this enables the allocation of network assets by group to reflect utilisation by that group.

There are five broad connection types (some have sub-categories to further delineate capacity requirements and better reflect cost to serve, such as the General group):

1. General – households, commercial businesses connected to the low voltage network, including single and 3-phase supply

2. Irrigation – connections with irrigation pumps (>20kW)
3. Industrial – industrial/commercial connections
4. Large Users – connections with dedicated assets and specific connection requirements[1]
5. Generation – distributed generators (>10kW).

We allocate our costs across these customer load groups based on the assets required to meet their energy needs.

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

Customer group	**General**	**Irrigation**	**Industrial**	**Large Users**	**Generation**	**Total**
Fixed	3%	0%	0%	2%	1%	6%
Variable	44%	0%	0%	0%	0%	44%
Capacity	0%	45%	4%	2%	0%	51%
Total	47%	45%	4%	3%	1%	100%

The price components used for pricing for each customer load group is shown here:

Fixed components	$/con/day			$/day	$/day
Capacity components		$/kW/day	$/kVA/day	$/fixture/day	
Variable components	$/kWh			$/kVA/day	

Where possible, we recover costs through fixed charges or capacity charges. However, we are compelled to comply with the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 ('Low Fixed Charge Regulations'). Whilst appropriate at the time, it was enacted more than fifteen years ago. It is our view that this regulation is creating a block to providing customers with more cost reflective prices and allowing network companies to recover more of their costs through fixed charges. This is because the regulations require a low 'fixed charge' component to the pricing design ($0.15 per day) and therefore a high variable component must be associated with the customer type. This fixed charge, totalling just under $55 per annum for a typical residential customer, in no way reflects or recovers the fixed costs that are associated with delivering electricity network services to customers who are eligible for this price category. Instead, the regulations force us to recover, or try to recover, the true cost to serve via variable prices.

For simplicity we allow all General (GS20) customers access to the Low Fixed Charge product type and have used it to shape the overall design of the wider 'General' product group. We acknowledge that this must change. We look forward to changes being made to the Low Fixed Charge regulations at a national level to enable this pricing reform to occur *. Until then, EA Networks is constrained in its ability to provide more cost-reflective product design across the entire product portfolio.

* We recognise that the General load group could be restructured any time. However, with potential change to Low Fixed Charge regulations looking imminent we have elected to

[1] Streetlighting costs are allocated to a Streetlighting customer load group. This load group is included in the Large user customer load group.

maintain the current structure and not put out customers through (potentially) more than one reform cycle.

Managing consumer impacts of pricing changes

We assess the impact on consumers of each change to price structure and price level. We take account of the potential the price change will result in bill shock for a customer load group, or consumers within a customer load group.

We believe that price stability is important and critical to the efficient running of the local economy, and our customer research confirms this. Our pricing is designed to minimise volatility between years across the customer load groups. This is to mitigate bill shock and assist them with efficient budgeting and planning of electricity expenses.

Price stability is maintained through consistency and our approach to price development. Only when critical to customers' needs or the financial stability of the business will we make changes to our Pricing Methodology.

Our customer load groups have also been developed to promote price stability and specifically reduce volatility.

> *For example: our Irrigation Price is a fixed daily charge based on connected kilowatts (kW) (capacity size). This charge is incurred irrespective of usage. We price in this way to ensure consistency each year in the price charged to irrigators and to signal to them the fixed costs incurred in building the network to meet their demand. If a variable charge was applied, it would be challenging to forecast demand and establish appropriate pricing to accurately recover our fixed costs. Variable charging would, for this load group, result in volatile prices between years.*

In addition to load group and price design, our board of directors approve any changes made to prices and this Pricing Methodology. Prior to any approval, a review is undertaken to firstly ensure compliance with the Default Price Path (DPP) determination. The board then take a holistic approach to determining the final changes (if any) to be made. Factors such as the fairness of a change as it affects our different customer load groups, the ultimate impact on these groups and the financial position of the company are, amongst other factors, considered and taken into account. Only when the board of directors is satisfied that all stakeholders have been considered and fairly treated will a change be approved.

Practically, this means discretion will be applied to a material increase in the level of any price component of the price structure for any customer load group. Options we have to manage price shocks include averaging the associated costs across other customer load groups or foregoing a portion of the Forecast Allowable Revenue.

For 2021/22, EA Networks worked to mitigate price shocks expected in 2022/23 and out years due to significant increases in forecast transmission costs (under a potential new TPM) by early repayment of Transpower New Investment Contracts. The early repayment avoids forecast significant increases in transmission costs in later years that may result in large year-on-year price increases.

Pricing considerations and objectives

Regulatory context

Our pricing is regulated by the Commerce Commission ('Commission') under Part 4 of the Commerce Act and the Electricity Authority under the Electricity Industry Act 2010, and Electricity Industry Participation Code 2010. These regulations ensure that distribution services are delivered at prices that are fair and reasonable and at an acceptable quality.

EA Networks' Pricing Methodology and prices are guided by and comply with regulations and guidelines governing the electricity industry, including:

- Distribution Pricing Principles published by the Electricity Authority.
  - We are expected to set efficient prices consistent with the Authority Pricing Principles published in June 2019. Appendix One describes how we do this.
- Electricity Distribution Information Disclosure Determination 2012 (ID Determination).
  - We are required to disclose information about our pricing approach and prices.
- Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004.
  - We are required to offer a low fixed charge tariff option (of 15 cents/day) for a consumer's primary residence.
- Electricity Distribution Services Default Price-Quality Path Determination 2020.
  - We are required to set prices to recover no more than the Forecast allowable revenue under the DPP determination.
- Electricity Industry Participation Code 2010, Part 6 (Connection of Distributed Generation).
  - Sets out requirements for setting prices for distributed generators connecting to and using our network.

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 LV with both overhead and underground variants of each. Overall, the distribution system is about 24% underground cable by circuit length.

The main settlement in the District is Ashburton township with about 17,000 residents. Smaller towns of Methven (1,400 people) and Rakaia (1,100 people) are also significant in terms of electricity consumer count. The district has a total population of about 30,000 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.

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 2003The network has peaked at 181MW twice in the past five years. Irrigation load has doubled since 2005 and now is about 147MW. This growth has in-turn driven significant capital development on the EA Networks network. However, irrigation load growth has now slowed.

We anticipate uptake of distributed generation and electrification of industrial processes (heat) and transport to impact our network. However, we have yet to observe any material change.

There is a significant amount of distributed generation on our network, though most capacity is associated with four distributed generators. By 31 January 2021 there were 277 connections with distributed generation, or 1.4% of all ICPs, with installed capacity of 32.8 MW. The largest Distributed Generation (DG) connection is Highbank, a hydro generator owned by Trustpower, with 28 MW capacity.

The number of small-scale distributed generation connections (<10kW) increased by 12% in the 12 months to 31 January 2021 from 233 to 260 connections. Capacity of small-scale distributed generation increased by 17% from 0.86 MW to 1.01 MW over the same period (all solar).

Solar generation capacity increased by 23% over the 12 months to 31 January 2021, from 1.06 MW to 1.31 MW mainly due to the connection of four larger (>10 kW) solar systems.[2]

Collectively distributed generators can provide about 20-25% of the energy needs of the district.

By 31 January 2021, there were 61 electric vehicles registered in Ashburton.[3]

Overview of Network Assets & Network Characteristics

The EA Networks 2020-2030 Asset Management Plan (AMP) comprehensively describes the network assets and network characteristics.[4] The following overview is from the AMP.

Network Inputs and Outputs:

Connections	19,814	Unique connections
Maximum Load Demand	181	MW (Dec 2020)
Delivered Energy	607	GWh (2019-20)
Annual Load Factor	42	% (2019-20)
Annual Loss Ratio	6.9	% (2019-20)

Substations	**Peak Load**	**Load characteristics**
Ashburton	19 MVA	Supplies 60% of urban Ashburton and some outlying areas. The load has a winter peak consisting almost entirely of residential dwellings.
Carew	15 MVA	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.

2 Source: https://www.emi.ea.govt.nz/r/mepwt.
3 Source: https://www.transport.govt.nz/statistics-and-insights/fleet-statistics/sheet/monthly-ev-statistics.
4 EA Networks Asset Management Plan 2020-30, available at: https://www.eanetworks.co.nz/assets/PDFs/Disclosures/Asset-Management-Plan/AMP_2020-30_Final.pdf.

Substations	Peak Load	Load characteristics
Coldstream	13 MVA	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	11 MVA	Summer peaks with irrigation load. The high general demand is a consequence of the large number and size of dairy sheds.
Eiffelton	9 MVA	Mostly irrigation.
Fairton	8 MVA	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 vegetable processing. Previously, the industrial load was non-seasonal, but total load peaked in summer with irrigation load. Another vegetable processing plant forms the base load.
Hackthorne	15 MVA	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	9 MVA	Mainly irrigation. Firm capacity exceeds maximum load.
Lauriston	15 MVA	Summer peaking due to irrigation demand. The high general demand is a consequence of the large number and size of dairy sheds.
Methven	5 MVA	Summer peaking due to irrigation demand. The high general demand is a consequence of the large number and size of dairy sheds.
Mt Hutt	2 MVA	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	2 MVA	A temporary substation located near the Montalto hydro power station.
Mt Somers	3 MVA	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.
Northtown	14 MVA	Provides additional capacity and security to Ashburton township and immediate surrounds. Load is winter peaking in line with residential demand
Overdale	14 MVA	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	16 MVA	Irrigation load causes this site to summer peak at 10 times its winter peak. Firm capacity is available to all load.

Substations	Peak Load	Load characteristics
Seafield	8 MVA	Dedicated to ANZCO's meat-works. Non-seasonal peak load
Wakanui	13 MVA	A summer peak load; mostly irrigation.

Source: EA Networks Asset Management Plan 2020-30, pp209-213

More detail on the EA Networks network characteristics is available in the Asset Management Plan, available at: https://www.eanetworks.co.nz/disclosures/asset-management/.

Customer context

The network has been designed to service customers (both load and generation) with their energy distribution needs. There are five main categories of customer (load groups):

1. General
2. Irrigation
3. Industrial
4. Large Users
5. Generation

The General and Irrigation customer load groups provide 92% of total revenue, with the General group providing 47% of total revenue and the Irrigation group providing 45% of total revenue. There are 18,138 low voltage residential and small business connections in the General group, and 1,614 connections in the Irrigation group.

Irrigation load can be high. During irrigation season EA Networks' maximum network demand can be three times higher, on average, than base load during winter. This is almost entirely driven by prevailing weather conditions and thus difficult to forecast. Irrigation demand during the season has a significant bearing on Transpower's interconnection cost that is charged to EA Networks and passed-on to our connected customers.

Consumer consultation

During October-November 2019, EA Networks undertook consumer consultation (conducted biennially, with the next survey due to be completed late 2021). This consisted of an independent survey of a random selection of end user customers.

EA Networks uses the results of consumer consultation in developing pricing strategy and pricing methodology. In summary, the results indicated that customers continue to be happy with the current level of prices, with a majority of those surveyed not willing to pay higher lines charges to reduce potential for outages or to reduce time without power. No questions were asked about the structure of our prices.

Feedback

We welcome feedback on our Pricing Methodology and any questions that customers may have regarding this or their specific circumstances. Any enquiries should be addressed to;

General Manager Customer & Commercial

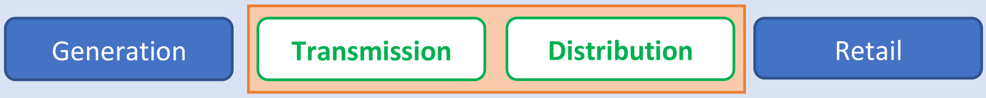
Phone (03) 307 9800, or email; enquiries@eanetworks.co.nz

Pricing methodology

Background

The purpose of this section is to outline in detail our methodology for setting prices and to disclose the current pricing derived from that methodology.

What our pricing covers



Electricity industry market segments. Our prices include costs relating to Transmission and Distribution only. Together these costs are referred to as Network Costs.

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.

It is Transpower's role to deliver electricity up and down the length of New Zealand (*Transmission),* taking energy supply from the *Generation* companies. Transpower hand-over within each region to the relevant Distribution Company via a number of Grid Exit Points (GXPs).

End user customers have their electricity relationship with Retailers. It is generally the *Retail* sector that charge end user customers for the total cost of electricity supply and usage. This charge includes all costs from the different market segments. As such, despite end users receiving only one electricity invoice each month, the four participants' costs and margins are included in that charge. We invoice retailers that have customers connected to our distribution network.

Our pricing (that is charged to Electricity Retailers) covers both *Transmission* and *Distribution* costs – together called *Network Costs*. Transmission costs are a direct pass-through of those charges levied on us by Transpower (the national grid operator). *Distribution* charges reflect the costs associated with maintaining and operating our electricity distribution network only. We disclose each separately in the Pricing Schedule.

This document details the methodology we use to derive pricing for *Distribution* and how we deal allocate *Transmission* costs that are ultimately included in our final prices invoiced to retailers each month.

Open access network

Our charges are passed on to retailers that use our network to provide electricity to end users. Retailers that wish to sell electricity to customers within our network area must sign a Use of Systems Agreement (UoSA). This agreement forms the commercial understanding between the Retailer and ourselves and covers myriad operational and performance objectives and responsibilities. It also details how we charge and how we will invoice retailers.

Our UoSA is based on the principle of open access and equivalence of inputs. That is, each retailer is treated equally regardless of size or any other differentiating factor. We do not have differential prices, service targets or operational procedures for each individual retailer. Whilst this maintains simplicity in how we deal with retailers, it also ensures an equal playing field and should enable greater competition within the retail sector.

Future pricing approach

The purpose of this section is to provide customers and interested parties with an indication of the direction that EA Networks sees pricing (in terms of methodology and pricing approach) heading.

Our prices are set taking account of the network, consumer and regulatory characteristics relevant to our network. As such, we recognise the importance of evolving pricing as circumstances and characteristics change.

We have a pricing development workplan which sets out a roadmap for evolving our pricing approach and pricing to offer pricing structures which reflect the underlying cost to supply the distribution service desired by our customers.

The near-term focus of the workplan is to identify the activities we will undertake to develop a pricing structure which – to the extent practicable – has fixed and variable price components which align to the fixed and variable costs of supply for each customer (load) group.

High level implication of future pricing approach

We believe it is important to signal early any changes to our methodology given the long-term nature of our investments and those of our customers, as may be affected by electricity network pricing approaches.

The impacts of the future pricing approach will differ for each customer load group and each customer. Identifying customer impacts of pricing changes is an action included in the pricing development workplan.

At a high level, the likely impact of transitioning to a pricing structure which has fixed and variable price components which align to the fixed and variable costs of supply for each customer group will be to increase the proportion of revenue recovered through fixed and fixed-like charges and reduce the proportion of revenue recovered through variable charges.

Two decades of significant network investment means the network has on-average significant capacity, with only isolated areas of network congestion which might result in marginal (avoidable) costs which would be reflected in variable charges. As such, most costs recovered through prices are expected to be fixed. This is the approach for the large user, industrial and irrigation customer groups.

The General customer group, however, can expect a gradual rebalancing of the levels of the variable charge and fixed charge, with the level of the variable charge falling and the level of the fixed charge increasing. The implication for these customers is an overall decline in the individual benefit of reducing or avoiding consumption by investing solar panels and batteries. There may continue to be localised benefits from reducing or avoiding consumption depending on the specific network conditions.

Pricing philosophy

Our philosophy to pricing is based on two views; the internal (business) view focusses on what we must do and what we require financially to operate our business.

The second view is external and that of customers and how we price in the most accurate and equitable way that we can. The external view considers the wider market including the regulatory framework that we work within and must comply with.

Internal perspective

We are a commercial organisation and therefore accurate pricing is fundamental to the financial sustainability of our business. Prices charged to use the services that we provide must recover our costs of doing business as well as ensure that we can maintain the assets required to deliver our services. Inherently our pricing is based on forecast information and therefore it is important that we have the most accurate information and assumptions to ensure that our prices result in actual revenue that in-turn recovers our cost of doing business.

Sustainability refers to the ability of the company to generate an adequate return to ensure that we can continue as a viable business (going concern). This requires revenue but also a strong focus on costs and management of our investment in network assets. Our investments are typically long term and therefore planning is very important so that we ensure decisions made today will not burden the company in the future.

Accuracy and *Sustainability* are therefore two over-arching principles that we focus on from an internal pricing methodology perspective.

External perspective

As well as considering internal requirements, we pay particular attention to external factors when considering our pricing methodology. There are four principles that underpin our approach to developing products and prices; *Simplicity, Stability, Equity* and *Transparency.*

By focussing on *simplicity,* we aim to have a pricing methodology that is easy to understand and follow whilst being cost reflective. It is critical to us that end user customers can understand the prices that they are charged in relation to the nature of their supply, and further, to appreciate why we charge for our services the way we do.

We believe that price *stability* is important and critical to the efficient running of the local economy. Businesses and residents need confidence in the prices they pay for core services such as electricity. Our pricing is designed to minimise volatility across the Customer Load Groups. This is to mitigate bill shock and assist them with efficient budgeting and planning of electricity expenses.

Equity is the fairness of our pricing, both between customer types as well as inter-generational customer groups. Whilst inherently difficult to apply charges that exactly correlate to the costs of supplying an individual customer, we endeavour to allocate the cost of running the business and the distribution network in such a way that those who use more, or drive more of the cost, in-turn pay for that (beneficiary pays). This is the purpose of establishing Customer Load Groups and identifying the assets and costs associated with running our network and allocating those accurately and fairly to each group of users.

We are entirely open and *transparent* with our methodology for pricing. We make this information publicly available and explain it in detail. Further, we engage with the community to share this information and seek feedback by way of customer surveys and regular interaction and communication with electricity users.

Through application of these over-arching principles we aim to create a pricing methodology that serves the needs of our business whilst meeting customer expectation.

Pricing development activities

The pricing development workplan sets out near and longer-term activities.

The workplan reflects the uncertainty about what may come, identifying near-term activities focused on preparing for pricing changes once more is known about the nature and timing of regulatory changes. There are material regulatory changes on the horizon, particularly to the LFC Regulations and adoption of a new TPM. However, the nature and timing of these changes is not currently known.

Near term pricing development activities are:

- overarching pricing development activities relating to obtaining information and capability required to identify pricing structures which meet the pricing objective and philosophy
- low fixed charge-related activities relating to responding to prospective changes to the low fixed charge regulations
- Transmission Pricing Methodology (TPM) activities relating to responding to prospective changes to the TPM

More detail is available in the Pricing Development Workplan on our website.

Our approach to developing prices

The development of our methodology and the prices that result is based on economic pricing principles given practical, physical, regulatory and commercial constraints.

In general, shared assets and shared costs are allocated proportionally across customer load groups using Network Capacity (kVA). Specific assets and specific costs that can be attributed to a specific group are allocated to that group only.

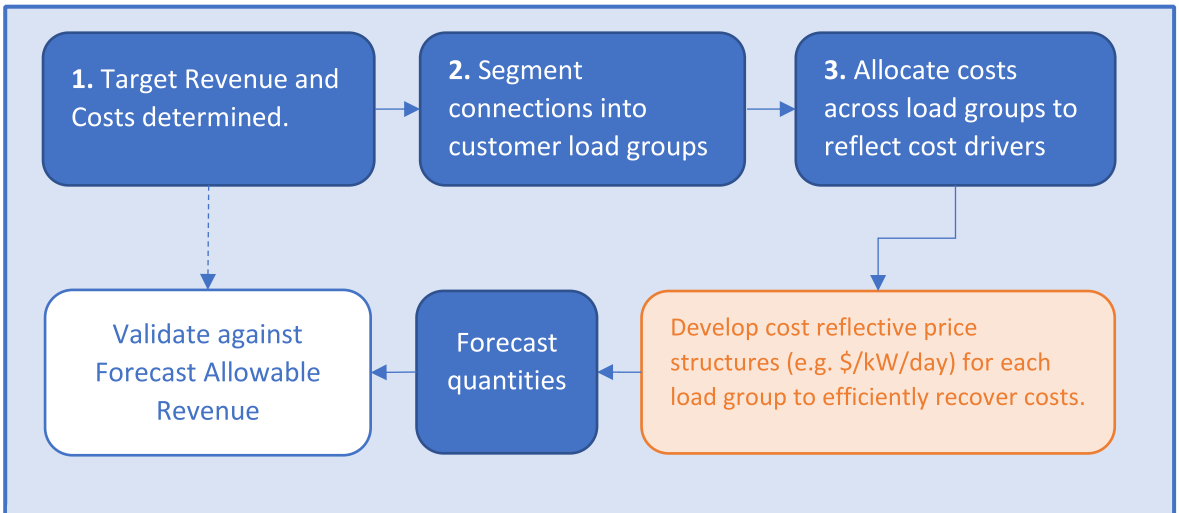
> *For example: if we build a new feeder (electricity line) that only allows irrigation connections to connect to the network, the costs associated with that line will be allocated only to the Irrigation load group. Other load groups pricing will be unaffected by this capital development.*
>
> *If on the other hand, we invest in equipment that improves the general quality of electricity supply (i.e. it benefits all connected users) then the costs associated with that will be shared amongst all load groups proportionally.*

There are practical limits to the information available to allocate assets and costs. Electricity networks generally have significant legacy assets upon which modern upgrades have been applied. In addition, technology improvements can and will be incorporated where appropriate, but these can take many years to have an effect across the aggregate network.

Consequently, when allocating assets and developing prices a degree of averaging is inevitable. Despite this, and by applying the four pillars of our approach to pricing, we aim to establish prices that do reflect the costs associated with supplying electricity to different end users (customer load groups).

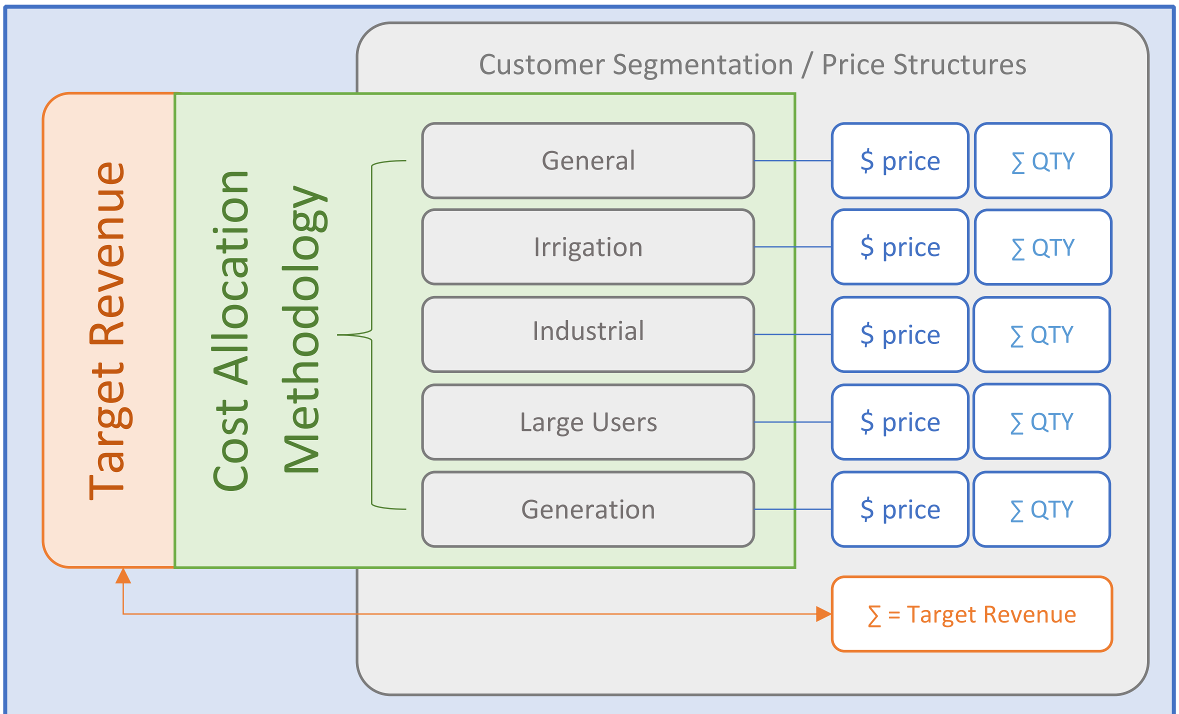
Price development process

The price development process is outlined in the following diagram.



Overview of Pricing Methodology

The following diagram illustrates how the process links together to form our pricing methodology and pricing.



Where QTY (quantity) may be volume, capacity, demand , number or any combination. See Pricing details for specific information.

Overview of Cost Allocation Methodology

Target Revenue and costs determined

Each year we review the costs associated with operating the electricity distribution network for the financial year (from 1st April to 31st March). These costs are separated into five key areas.

- Distribution services costs:
    - Operations and maintenance
    - Administration
    - Depreciation
    - Cost of capital (return on investment)
- Pass-through and Transmission costs:
    - Rates & levies
    - Transmission.

The sum of these five costs is our ***Target Revenue***.

This table shows the main costs making up the Target revenue for 2021-22.

Cost category		Target revenue ($000)
Distribution services		
	Operations & maintenance	$7,972
	Administration	$5,086
	Depreciation	$10,419
	Cost of capital	$9,575
	Subtotal	**$33,052**
Pass-through costs		
	Rates & levies	$0.379
Transmission		
	Transmission – connection	$1,053
	Transmission – interconnection	$6,682
	Transmission – subtotal	$7,735
	Subtotal	**$8,114**
Target revenue		**$41,166**

Note: Forecast revenue from new connections is not included in Target Revenue for calculating prices..

We use historic financial information and known changes (e.g. staff numbers changing affecting salaries and wages) to derive operations and maintenance, administration and depreciation cost trends to forecast these costs for the next financial year.

Cost of capital is unique in that it is not separately identifiable (additional steps are required to determine the value of cost of capital). To calculate Cost of Capital; first, we determine our *Forecast Allowable Revenue* as calculated under the Default Price Path regulatory regime (or lower target as specified by our Board). This is effectively the total return on assets we are allowed to earn as defined by the Commerce Commission (the Regulator). Secondly, we subtract the costs already identified (operations and maintenance, administration depreciation, and Transmission) with the difference being our Cost of Capital.

At all times our Forecast revenue from Prices is compared with Forecast allowable revenue to ensure that we develop prices (and therefore derive revenue) that is consistent with the Default Price Path as determined by the Regulator.

For the financial year ending 31st March 2022 our Target Revenue is **$41.166 million**.

Segment connections into customer load groups

Segmenting connections into customer load groups allows us to establish prices that better reflect the nature of assets and costs incurred in delivering electricity to specific groups of customers.

> *For example: the assets and costs associated with delivering low voltage connections to the average family home are significantly different to those required to deliver electricity to an industrial manufacturing business. Segmentation is essential so that one group is not subsidising another group or being disproportionately charged for infrastructure that they are not benefitting from.*

The criteria for segmenting connections is to group connections that share similar electricity usage patterns (load profiles), have similar demand requirements (e.g. criticality of supply and diversity needs) and that drive similar incremental cost to our business. This this enables the allocation of network assets by group to reflect utilisation by that group.

Once connections are segmented logically, *customer load groups* are created. We aim to have as few groups as possible as we believe that this simplifies the pricing methodology and the derivation of prices. It also improves segmentation accuracy by reducing the potential for a customer to be consistent with more than one group.

From this segmentation process we have created five customer load groups;

- General (low volt)
- Industrial (medium volt)
- Irrigation (medium volt)
- Large Users
- Generation

Where the segments are broad we have established sub-groups within each (where appropriate) that allows better granularity when it comes to allocating prices to end users. However, the pricing methodology applied to these sub-groups is identical within the broader group, all that may change is the unit price between sub-groups usually based on connected capacity (kVA).

> *For example: within General (low volt) we have five sub-groups that differ based on size of connected load – GS05 (up to 5kVA), GS20 (up to 20-25kVA), GS50 (up to 50kVA), G100 (up to 100kVA) and G150 (up to 150kVA).*
>
> *The methodology for allocating costs and determining prices is identical for the five sub-groups, all that changes is the unit price (the larger the connection, the higher the price in this instance).*

In essence – a customer who has higher network needs, uses more of the available network capacity and/or requires more network assets to deliver their energy requirements will pay more through our network prices. Put another way, a customer can reduce their network prices by reducing the capacity or amount of demand they place on the electricity network.

Each customer load group is described in more detail later.

Allocate costs across customer load groups

The *Cost Allocation Methodology* simply refers to the way that we allocate our Target Revenue (by category) across the customer load groups. The intention of the methodology is to establish a relationship between the customer load groups and the costs associated with supplying electricity to them – in other words, how to recover Target Revenue in the most cost reflective way that we can. From this we can derive pricing by customer load group.

> *For example: we may construct a sub-station to supply a single Major User. The costs associated with this are allocated to that user and their pricing reflects recovery of those costs. Other Customer Load Group pricing is unaffected by those costs.*
>
> *However, if a sub-station services all Customer Load Groups, the costs associated with it a shared proportionally by all groups.*

Summary of allocation method

Cost	Allocation method
Pass-through and Transmission	Any time maximum demand of customer load group
Distribution services costs:	
Operations and maintenance	Any time maximum demand of customer load group
Administration	Number of connections (ICP's)
Depreciation	Any time maximum demand of customer load group
Cost of capital (return on investment)	Anytime maximum demand of customer load group

Pass-through and Transmission costs

Transmission costs are passed on to us by Transpower. There are two costs incurred; Connection Costs and Interconnection Costs.

Connection Costs recover the costs Transpower Assets require to connect our Network to the Transpower Network i.e. the local Transpower Substation. For 2021-22, connection costs are forecast to be 3% of target revenue.

Interconnection Costs, which drive most of our Transmission Costs, recover the cost of Interconnection Assets i.e. Transpower Lines. For 2021-22, interconnection costs are forecast to be 16% of total revenue.

As interconnection assets are also used to supply other Lines companies, interconnection costs are shared based on the demand measured for each distribution network during the 100 half-hour peak demand periods on the Upper South Island region (known as the Regional Coincident Peak Demand – RCPD). These peaks are recorded each year by Transpower. We allocate these costs to each customer group based on that group's contribution to total network capacity used.

We allocate Transmission Cost by applying the proportional contribution to total sub-transmission Network Capacity (kVA) less any non-contributing capacity.

Transpower notify us each year, in advance of setting our prices, what their charge will be for the coming year. We apply no margin to the Transmission charge. It is a direct pass-through of Transpower's notified charges to us.

Transmission costs include pass-through costs, specifically, local authority rates and regulatory levies. These are forecast to be 1% of total revenue for 2021-22.

Administration costs

We allocate Administration Costs based on the number of Installation Control Points (ICP's). This is an equal allocation but one that sees accurate sharing of this general cost on a per connection basis. We hold the view that Administration Costs increase or decrease in line with the volume of connections more than any other metric.

Operations and Maintenance, Depreciation and Return on Investment costs

We allocate the costs of Operations and Maintenance, Depreciation and Return on Investment based on the share of the replacement cost of assets. We allocate the replacement asset value across customer load groups using two methods.

The primary allocator of costs is the replacement cost of Dedicated Assets used. Where possible we allocate the specific assets used by each Customer Load Group to that group. As such we take our Total Asset Pool and allocate Dedicated Assets to the appropriate customer load group. A summary of the result of this allocation can be seen in Appendix D.

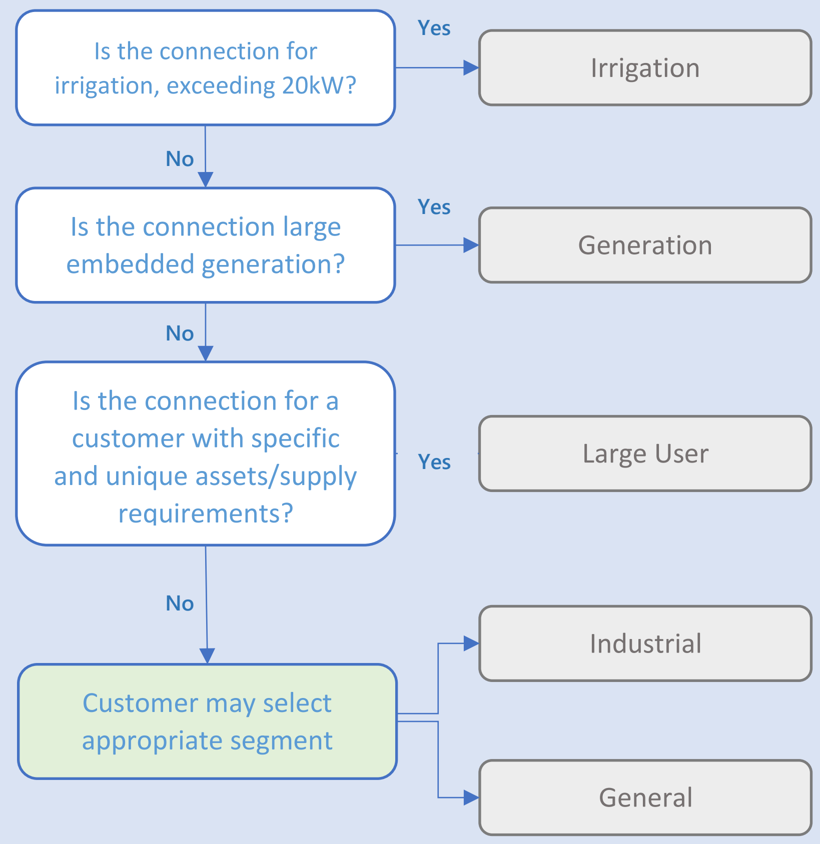
The secondary allocator for the residual Total Asset pool is network capacity (kVA), i.e. a proportional allocation across all load groups based on network capacity used. We believe that this is the best proxy for allocating shared assets fairly to each customer load group. Network capacity is before diversity demand at the medium voltage bus based on anytime maximum demand.

More detail on connection segmentation approach

The following section provides detail of our Pricing Methodology at the customer segment level. It expands on the earlier section to provide readers with increased granularity on specific parts of the methodology and approach that we use relating to each customer load group. Customers have some optionality regarding their segmentation in most circumstances unless the cost drivers relating to their connection type are quite specific (e.g. irrigation exceeding 20kW installed capacity).

Your customer load group

The following generic approach is used to determine which customer load group you are in;



Customer segmentation decision tree

The approach is flexible as it allows most customers to choose which customer segment they belong to and within each segment there are 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 on the General tariff 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.*

General customer load group

Number of customers	18,138
Load group target revenue	$19.27 million (47% of total)

The General customer load group is for any connection made to our low voltage (400 volt) network including single and three phase supplies except for irrigation connections that exceed 20kW.

End users within this load group are charged a two-part price, with a fixed component and a variable component. The variable component can have several sub-components depending on the end-user's preferences, and metering configuration.

The fixed component is based on the maximum capacity of their supply (size of their fusing) charged in $/day.

The variable components are based on the quantity of electricity consumed (kWh) charged in $/kWh. The volume charge is further separated between Controlled and Uncontrolled supply. There are multiple meter options available to provide customer choice with regards to their Controlled, Uncontrolled and Night-time usage.

It is irrelevant to us whether the connection supplies a business or residential user – this is because our cost drivers are not dependent on that distinction, but rather the assets employed to supply electricity to the Installation Control Point (ICP) and our ability to control load (supply).

> *For example: it can often be challenging and subjective to differentiate a business connection from a residential connection. As our costs are not affected by this differentiation it is meaningless to attempt to segment based on that differentiation. Rather, it is more accurate to use actual data that is linked to our cost drivers – size of connection is known by the type of fusing and can be easily determined as can the average cost. In addition, actual usage can be measured using electricity consumption meters and whether the site is controlled or uncontrolled.*

Price calculation

The General segment has various sub-groups to provide flexibility and choice to the customer. To comply with low user regulations, we offer a standard price at $0.15 fixed rate per day price component (GS20). Most of the low voltage customers are on this price that relates to approximately 20-25kVA supply. Focussing on simplicity, as supply capacity increases, we increase the fixed daily charge proportionally.

> *For example: GS50 (50kVA supply) is $0.30 per day, doubling the capacity to 100kVA doubles the fixed daily charge to $0.60 per day.*

We determine the total recovery of Target Revenue for the General segment from fixed charges, and the balance of Target Revenue is recovered from the variable usage charge.

To provide further flexibility to customers and to also incentivise different energy consumption profiles, we offer two variable use prices: Controlled and Uncontrolled.

Controlled Energy allows us to shed load (temporarily cease supply) when required during peaks on our network or the wider Upper South Island region. This could be during times when energy consumption across our network needs to be reduced (typically when we are nearing our maximum capacity). The ability to control load is very important to network operation as it allows us to invest more efficiently to deliver electricity to a customer. Since we can control this load, we incentivise use of this price by offering it at a lower variable rate compared to Uncontrolled.

Uncontrolled Energy is constant supply, 24 hours per day. We have no operational ability to cease supply to these connections. For this reason, we charge more for this type of supply than we do for Controlled supply.

The Controlled Energy price is a legacy price that was established at a significant discount to the Uncontrolled Energy Price. To continue with stable pricing, we have not altered this differential and any adjustments to prices are reflected equally between the two prices.

Based on load profiling, we calculate the usage of each ICP within the General segment from the previous year's statistical result plus forecasted changes. We then multiply this by the Controlled Energy rate, from this we obtain a total revenue estimate for that price.

To determine the Uncontrolled Energy rate, we take total Target Revenue for this segment, deduct revenue from the fixed charge and the variable Controlled Energy charge to obtain a shortfall. This shortfall represents the Target Revenue required for our Uncontrolled Energy price. Again, by applying load profiles for each ICP we determine a rate for this price.

Target revenue is achieved by summing the revenue for each component: fixed rate, variable Controlled Energy, and variable Uncontrolled Energy.

Prices available

Price Code	*Description*	*Units*
GS05	General Supply – less than 5kVA	$/day
GS20	General Supply – 20kVA	$/day
GS50	General Supply – 50kVA	$/day
G100	General Supply – 100kVA	$/day
G150	General Supply – 150kVA	$/day
GUEN	Uncontrolled Energy	$/kWh
GCOP	Controlled Off-Peak Energy	$/kWh
G10N	Night Boost 10	$/kWh
GNEN	Night only rate	$/kWh
GEDG	Export kWh	$/kWh
GUDG	Generation Credit	$/kWh
MCRF	Floodlight – Closed	$/fitting/day
MCRU	Under Veranda - Closed	$/fitting/day

Irrigation customer load group

Number of customers	1,614
Segment target revenue	$18.41 million (45% of total)

The Irrigation customer load group is unique in that these connections are for a specific purpose, irrigation, or more specifically, electric pumps on a single connection (water/effluent pumps including centre pivot motors for example).

We have a specific price for irrigation connections because they typically create a seasonal load unlike other energy users that have a load profile spanning the calendar year. The resulting specific load profiles influence costs, particularly relating to costs of meeting peak demand requirements.

Irrigation is seasonal and weather dependent. Irrigation typically starts during September/October and ends around March. It occurs when water is required on crops and pasture. If it has been particularly wet, then irrigation usage reduces. Conversely during dry periods irrigation can be at full capacity and for many days or weeks throughout the season.

These specific characteristics have implications for network costs. We have designed our network to meet maximum demand in any area. We do not control irrigation connections and therefore we price for the maximum demand that is made available. We have had feedback directly from irrigators that a controlled load would be unacceptable to their operation hence our network design is based on maximum demand availability.

However, during 2019 we introduced a voluntary trial programme that incentivises the use of irrigation outside of peak periods. Customers selecting this trial tariff (ISMR) lowered their daily fixed charge by $0.10 per kilowatt. Connections were monitored for compliance during the season and any connection found to be non-compliant (i.e. used energy during identified peak periods) was reverted back to the standard irrigation tariff. ISMR is now closed to new customers.

End-users in the irrigation load group are charged a one-part price, with a single $/kW/day fixed component. We price irrigation based on maximum capacity of the connection, since usage is irrelevant to our cost drivers.

Some end-users may also face price components relating to their impact on quality of supply from harmonic distortion.

Relating this to our pricing principles, this approach ensures stability by allowing irrigators to fix their prices for our services. It also maintains simplicity, by having a straight-forward method for calculating the cost of the service. Transparency, through open and honest communication of how we derive this price and why we price the way we do, and finally equity; we are charging irrigators for the cost of their capacity and assets required to deliver a maximum demand service to them. In addition to this last point, urban and other non-irrigation customers are not subsidising assets required for the irrigation load.

Price calculation

To ensure that we manage our risk, we apply only a fixed rate charge to the irrigation price. There is no variable component in our charges due to the inherent difficulty forecasting usage profiles for irrigation connections. This means that whether a connection is being used or not, the customer will incur the fixed daily charge.

We calculate the value of assets required to service irrigation customer based on Network Capacity (after accounting for Dedicated Assets). This allows us to determine the appropriate share of Target Revenue for the Irrigation Price.

Based on our record of irrigation connections, and our related record of connection size, we divide the Target Revenue by the installed capacity and further divide this by 365 to establish a daily rate per connected kilowatts (kW).

Only irrigation connections exceeding 20kW capacity are required to be on the Irrigation Price.

Harmonics mitigation incentive and Differential Price

During January 2014, we changed our connection standard with respect to Variable Speed Drives (VSD) on irrigation price connections. From that date, all irrigation connections with a VSD and cumulative load exceeding 20kW are required to have a harmonic filter installed or make other adjustments to their connection to mitigate the adverse effects of harmonic distortion.

To assist customers affected by this change we established a one-off discount paid once a customer became compliant with our revised standard. This programme is now completed and the discount is no longer available.

Those customers that did not make their sites compliant with our connection standard had their ICP placed on the Irrigation Harmonic Penalty tariff. Connections on this tariff can only revert to the standard irrigation tariff (ISCH) after becoming compliant. The differential price adds $0.10 per kW per day over and above the prevailing Irrigation price rate (ISCH).

More information regarding this standard can be found at:

www.eanetworks.co.nz/power/network-harmonics

Prices available

Price Code	***Description***	***Units***
ISCH	Irrigation – Connected kW	$/kW/day
ISCF	Irrigation Harmonic Penalty	$/kW/day
ISCH	Irrigation – Managed Trial (now closed)	$/kW/day
ISMR	Irrigation – Managed Rebate (now closed)	$/kW/day

Industrial customer load group

Number of customers	44
Segment target revenue	$1.75 million (4% of total)

The Industrial customer load group is for connections wanting the ability to manage their distribution costs by managing their energy use (under a specific maximum demand).

End-users have the choice to switch between General and Industrial.

End-users in this group are charged a single price based on their daily peak demand, measured in kVA.

All Industrial connections must have a Time of Use Meter installed to record Maximum Demand. This price group is not available to any seasonal supply customers such as irrigation.

Price calculation

All revenue derived from the Industrial group is recovered based on maximum demand (both network and transmission recovery) measured in $/kVA/day. This provides an incentive to customers to manage their peak demand, which in-turn can reduce our requirement to invest in upstream assets. End-users can have different rates based on their metering configuration and whether we can control load at that location.

The Industrial Supply kVA Anytime Demand price is based on demand that is measured on peak half-hourly demand over the billing period (one month).

Industrial Supply kVA – Day Demand has peak demand measurement limited to the hours of 8am to midnight.

Industrial Peak Demand – the Peak Demand component relates to transmission which is measured between 4:30pm and 9:00pm weekdays excluding public holidays. The Anytime component is based on the peak half-hourly demand over the billing month.

Prices available

Price Code	Description	Units
ICMD	Industrial Supply kVA - Anytime Demand kVA	$/kVA/day
IEMD	Industrial Supply kVA - Uncontrolled Energy	$/kWh
ICDYMD	Industrial Day Demand - Day Demand kVA	$/kVA/day
ICDYAD	Industrial Day Demand - Anytime Demand kVA	$/kVA/day
IEDS	Industrial Day Demand - Uncontrolled Energy	$/kWh
ICDPD	Industrial Peak Demand – Peak Demand	$/kVA/day
ICDAM	Industrial Peak Demand - Anytime Demand	$/kVA/day
ICEN	Industrial Peak Demand - Uncontrolled Energy	$/kWh

Large user customer load group

Number of customers	13
Segment target revenue	$1.33 million (3% of total)

The Large user customer load group is for connections supplied through separately identifiable assets and/or connection requirements. Each Large User has its own Price Code since the pricing to them is unique due to the dedicated assets usually employed to supply them. Despite being coded individually the users remain connected to an electricity retailer and therefore are covered by our standard UoSA.

Price calculation

Our pricing to Large Users is fully explained through direct contact with each user when they connect to our network. The approach and methodology is identical to all other segments. We believe that direct negotiation allows the specific requirements of the customer to be met. They are generally atypical users that have bespoke supply requirements and it is important that we meet their requirements wherever possible.

We charge a fixed monthly rate based on connected capacity (measured in kVA but charged $/day, fixed). This allows for the recovery of both dedicated and shared assets. This approach provides certainty over their electricity supply costs and enables choices to be made regarding capacity – there is a direct correlation between the size of the installation and the cost of supply. We value dedicated assets the same way as shared assets by using replacement cost.

Large users can also choose a $/kWh or $/kVA/day price component. This provides a mechanism for demand response and relates to Transpower transmission interconnection costs.

> *For example: we charge Mt Hutt a variable transmission cost $/kVA/day for energy consumption during peak periods. This incentivises Mt Hutt to utilise electricity for snow making during off-peak periods (i.e. non-weekdays between 11pm and 7am).*

Generally, we charge a variable transmission rate where they contribute to peak usage (that incurs interconnection costs). Where they elect not to use electricity during peak periods there is no variable transmission charge levied.

Prices available

Price Code	*Description*	*Units*
LUCM	CMP	$/day
LECM	CMP Energy	$/kWh
LMCM	CMP MD	$/kVA/day
LUPP	Silver Fern Farms	$/day
LEPP	Silver Fern Farms Energy	$/kWh
LMPP	Silver Fern Farms MD	$/kVA/day
LUMH	Mt Hutt	$/day
LEMH	Mt Hutt Energy	$/kWh
LMMH	Mt Hutt MD	$/kVA/day
LUHP	Highbank Pumps	$/day
LEHP	Highbank Pumps Energy	$/kWh
LMHP	Highbank Pumps MD	$/kVA/day
MCSL	Street Lighting	$/fitting/day

Large generation customer load group

Number of customers	4
Segment target revenue	$0.41 million (1% of total)

The Large Generation customer load group is for specific generators.

Presently we have four large distributed generators operating on our network; Highbank, Montalto, Cleardale and Lavington. As with Large Users, we explain electricity supply charges directly with these customers when required due to the bespoke nature of their requirements.

We act in accordance with the requirements of Part 6 (Connection of distributed generation) of the Electricity Participation Code 2010 when dealing with generation customers.

Allowance is made for variable cost pass-through, but these rates are presently set to zero.

Price calculation

When pricing for large distributed generators we have regard to;

- The value of dedicated assets (transformers, switch and fusing equipment) required for the customer connection to the distribution network, and;
- The value of network assets (shared between all load groups) that must be upgraded (upstream assets).
- Individual requirements of the Large Distributed Generator.

This detail ensures that the pricing charged to these customers is reflective of the costs incurred to enable grid connection. Each Large Distributed Generator has half hourly metering installed. The half hourly metering allows us to determine the distributed generators contribution to Transpower's:

- HVDC costs (100% pass-through to the distributed generator)

As per Electricity Authority decision of 5th February 2019, distributed generation on our Network are not be eligible to qualify to receive avoided cost of transmission payments from 1st October 2019.

Prices available

Price Code	*Description*	*Units*
LHUB	Highbank	$/day
LEHB	Highbank Energy	$/kWh
LMHB	Highbank MD	$/kVA/day
LTHB	Highbank Interconnection RCPD Credit	$/day
LHHB	Highbank HVDC Pass-thru	$/day
LUMO	Montalto	$/day
LEMO	Montalto Energy	$/kWh
LMMO	Montalto MD	$/kVA/day
LHMO	Montalto HVDC Pass-thru	$/kVA/day
LUCD	Cleardale	$/day
LECD	Cleardale Energy	$/kWh
LMCD	Cleardale MD	$/kVA/day
LTCD	Cleardale Interconnection RCPD Credit	$/day
LHCD	Cleardale HVDC Pass-thru	$/day
LULN	Lavington	$/day
LELN	Lavington Energy	$/kWh
LMLN	Lavington MD	$/kVA/day
LTLN	Lavington Interconnection RCPD Credit	$/day
LHLN	Lavington HVDC Pass-thru	$/day

Other information

Consumer consultation

We take a proactive approach in gathering the views of consumers using the electricity distribution network. Every 24 months an independent survey is carried out specifically to address pricing and consumer expectations regarding outages and quality of supply (and how these relate to price). The survey samples residential (urban and rural) and small business customers. The output of any survey or relevant public information is used when determining prices and other business matters such as capital investment. Our next customer survey is due for completion in the final quarter of 2021.

In addition to our bi-annual survey that directly targets consumers, 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 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.

Our single largest shareholder is the local District Council. This entity is also one of our largest connected customers and is represented on the Shareholders Committee. We seek and receive regular direct feedback in relation to pricing from the District Council.

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.

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.

Low user regulations

We are required to comply with the low user regulations[5] that require both Distributors and Retailers alike to offer low fixed charge prices. Specifically, we are required to offer a fixed line charge price not exceeding $0.15 per day (excluding GST) to residential home users that have usage at or below 9,000 kWh per annum. We provide this price within our General customer segment, refer to price code GS20 (General).

Whilst the original intent of LFC regulations were sound, we believe they are no longer fit for purpose. Specifically, the design of the regulation allows those customers that can afford to install solar panels (to self-generate electricity on sunny days) to inefficiently avoid paying for network charges. This puts the cost of supply onto other customers that cannot afford or are not able to install solar. In our view the low fixed rate, high variable rate design of the LFC regulations must change. For EA Networks to provide more cost reflective pricing signals it is imperative that these regulations are replaced. We support industry reforms aimed at achieving this.

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

Non-standard contracts

EA Networks does not have any customer or group of customers on non-standard contracts. All end users are contracted (ultimately) to the network via our standard UoSA that we have with each Retailer operating on our network.

Capital contributions

We have separate capital contributions within our New Connections and Extensions Policy, this is available on our website or from our offices.

We receive capital contributions for upgrades and network extensions.

For Rural & Rural Residential Connections greater than 300 kVA each capital contribution is bespoke and priced based on time and materials required to complete the specified work. However, it is based only on the incremental cost to connect the customer – that is the cost of the network assets that are incremental to any standard connection. This includes any upstream assets that must be upgraded to enable the connection to be made.

> *For example: if a new customer connection required 100 metres of additional overhead line to reach the connection point (ICP), the customer would pay for the cost of this new line, related poles and other identifiable costs. They would not typically be charged for a transformer as this cost is captured within the standard connection fee (which would also be charged). In addition, if we had to upgrade the entire line from single-phase to three-phase, the customer would be charged the cost of performing this upgrade.*

There is a high level of transparency of pricing made available to affected customers in a consistent manner to our general pricing methodology.

For Rural & Rural Residential Connections less than and equal to 300 kVA standard capital rates apply. The standard capital contribution rates are listed in Schedule A of New Connections and Extensions Policy.

Discretionary discounts and rebates

We do not have a specific policy regarding discretionary discounts, rebates, or dividend. From time to time we pay a deferred discount to all customers on our electricity distribution network. However, this is driven by the financial position of the company and only at the discretion of our Board of Directors following input from management.

EA Networks may, in its sole discretion, elect to pay a dividend to shareholders in lieu of any discount or rebate.

APPENDIX A – Alignment with Electricity Authority Pricing Principles

Alignment with Electricity Authority pricing principles

The Electricity Authority has Pricing Principles[6] that provide an approach for developing and assessing pricing methodologies for electricity distribution companies. 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);

Forecast revenue and prices for each customer load group (in aggregate) are greater than attributable avoidable costs and less than attributable standalone costs, except for the General customer group. We look forward to changes being made to the Low Fixed Charge regulations at a national level to enable greater flexibility in pricing to signal the economic costs of service provision. Until then, EA Networks is constrained in its ability to provide more cost-reflective product design across the entire product portfolio.

The workplan includes activities to confirm the allocation of costs of supply to each customer load group and the extent of alignment between price levels and price components. These activities will confirm relationship between prices and avoidable and standalone costs.

Where expansion is required, we generally fund this by way of capital contribution from the party driving that expansion.

For example, if we are required to extend our existing overhead power 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).

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

Prices for each customer load group broadly signal the impacts of network use on economic costs, except for the General customer load group (due to the approach take to comply with the low fixed charge regulations).

The pricing workplan includes activities to confirm the pricing structures align with the overarching pricing approach and to ensure price component of the structure for each customer load group signals – to the extent practicable – the impact of network use on economic costs. Changes to the TPM are expected to result in current pricing more closely aligning with economic costs.

[6] Distribution Pricing Principles, published by the Electricity Authority, June 2019.

Price structures for irrigation, large users and generation use fixed and capacity charges to signal the impact of network use on economic costs. For 2021-22, 100% of costs allocated to these groups are recovered using fixed and capacity charges. Controlled load pricing and capacity charges are currently used to signal opportunities for load management – i.e. to signal that increasing capacity increases our cost to serve.

Fixed charges are set using connection capacity, with the daily fixed fee rising in-line with the increased size of the connection. Connection size is a reasonable proxy for a consumer's responsiveness to the fixed charge level. That is, customers that require a larger connection to ultimately consume more electricity are likely to expect to pay a higher amount for that connection. As larger connections drive greater cost onto our business this has the added benefit of recovering those costs more accurately.

In addition, we provide prices structured to suit those users that have maximum demand needs (irrigation) by offering a fixed daily capacity charge with no variable component. This removes price volatility that could result due to the unpredictability of load and usage which would result from volume-based charge.

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

We signal the level of available capacity, and differences in services, through pricing to reflect the needs of each customer load group. Some customers require uncontrolled capacity regardless of time of day (e.g. irrigation). The price for irrigation is therefore based on the cost of creating this capacity (maximum demand) and is a fixed daily charge. For others that have less critical demand where we can control load, associated prices are created that signal this fact.

We do provide for non-standard agreements and negotiate directly with large users for their electricity distribution needs. This allows bespoke pricing to be established that meets the unique circumstances of the customer (e.g. for atypical load patterns, higher levels of redundancy or to address particular by-pass or alternate energy substitution situations).

(iv) ENCOURAGING EFFICIENT NETWORK ALTERNATIVES.

We set our prices to encourage efficient network alternatives. Customers in the General customer load group are encouraged to opt for demand response supply through our controlled load prices. These prices provide a significantly reduced rate compared to the uncontrolled variable rate.

We consider the increasing availability of solar DG, batteries and energy management capability provides opportunities for us to work with end-users to optimise network use (particularly peak demand) and network capacity required (timing of network upgrades).

A specific opportunity to refine prices to encourage efficient network alternatives, and manage peak demand impacts, exists with our pricing approach for the Irrigation load group. Doing so could also assist with managing the significant volatility in transmission costs.

(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.

Our differentiated Customer Load Groups and related prices are designed provide a range of prices that better reflect usage types at a more granular level, varying the level of fixed versus variable charging.

Generally, a price that has a higher level of fixed charging will have reduced variable charging. This is critical in the price structure to ensure that costs are fairly recovered whilst also providing appropriate pricing signals.

We look forward to changes being made to the Low Fixed Charge regulations at a national level to enable greater flexibility in pricing to signal the economic costs of service provision. Until then, EA Networks is constrained in its ability to provide more cost-reflective product design across the entire product portfolio.

(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 contracts to consumers who have non-standard 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 customer load group are encouraged to opt for demand response supply through our controlled load prices. These prices provide a reduced rate compared to the uncontrolled variable rate and aim to reflect the value of load management.

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

We work to make sure our prices are developed in a transparent way. We publish this Pricing Methodology and provide information on our website on the Customer Load Groups, prices, pricing and related statistical information.

When we increase prices we do so with due regard given 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 discussing pricing with other EBD's to help with standardisation of tariffs, 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 four customer load groups and not more than sixty specific prices. Changes to this are limited and only made when necessary for new customers or for changes to the business.

Our Default Distributor Agreement is open access and all retailers share the same terms and conditions. Specifically, all retailers have access to the same prices and no retailer incurs differential pricing or service levels of any kind.

APPENDIX B – Alignment with Commerce Commission Information Disclosure

The following excerpt is from the Electricity Distribution Information Disclosure Determination 2012 that relates to disclosure of pricing methodologies. We have included this for ease of reference. The numbering relates the original document.

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-	***Process obligation – disclose (publish) by 1 April each year***
(1) Describes the methodology, in accordance with clause 2.4.3 below, used to calculate the prices payable or to be payable;	***Describe the methodology according to requirements in 2.4.3***
(2) Describes any changes in prices and target revenues;	• p5, change in Target Revenue "…a 11.4% reduction from $46.4 million in 2020-21." • p5, "The reduction is mostly due to a $5.3 million or 40.8% reduction to transmission costs…" [and table] • p6, Average change in prices for 2021-22. "Prices for each customer load group will on average reduce for 2021-22 by 13.1%..." [and table] • p45, Appendix C Pricing Schedule 2021/22 presents prices for each Customer Group / Price Category from 2020/21 to 2021/22
(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);	Describe pricing approach for **non-standard contracts and distributed generation** according to requirements in 2.4.5. • Approach described at p34.
(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.	• p14, **Consumer consultation** section. "During October-November 2019, EA Networks undertook consumer consultation (conducted biannually). … In summary, the results indicated that customers continue to be happy with the current level of prices, with a majority of those surveyed not willing to pay higher lines charges to reduce the potential for outages or to reduce time without power." ○ Refer Global Research, EA Networks Customer Survey Results, January 2020 (Pricing

Information Disclosure Requirement	Reference in this document
	responses) • p33, **Consumer consultation** section. "Every 24 months an independent survey is carried out specifically to address pricing and consumer expectations regarding outages and quality of supply (and how these relate to price)." …
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.	***Process – disclose changes to methodology 20 days before new prices take effect*** • No change to pricing methodology in 2021/22.
2.4.3 Every disclosure under clause 2.4.1 above must-	***Elaboration on requirements in 2.4.1***

(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;	• p8, **Overview of pricing methodology** section gives overview of pricing development process
	• p18, **Our approach to developing prices** section gives detail on each process step, including assumptions and criteria used, eg,
	  ○ p19, price development process
	  ○ pp21-22, how connections are assigned to customer load groups – criteria are load profile, peak demand, capacity requirements
	  ○ p24 graphic showing key criteria for assigning connections to customer load groups
	  ○ p22, measures for allocating costs across customer load groups (see table)

(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;	• p35, Appendix A – Alignment with Electricity Authority Pricing Principles, provides assessment against June 2019 principles a) – d) including sub-principles.
(3) State the target revenue expected to be collected for the disclosure year to which the pricing methodology applies;	Target revenue stated p5 (text and table)
(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	• p7, **Target revenues by cost category** section. Table – target revenue by Customer Load Group; Table – Target revenue by Cost Category • p20, **Target revenue and costs determined** section. Table presents figures for five cost

Information Disclosure Requirement	Reference in this document
must include the numerical value of each of the components;	categories

(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;
	• p21, **Segment connections into customer load groups,** describes the approach for assigning connections to load groups
	  ○ "The criteria for segmenting connections is to group connections that share similar electricity usage patterns (load profiles), have similar demand requirements (e.g. criticality of supply and diversity needs) and that drive similar incremental cost to our business."
	  ○ "We aim to have as few groups as possible as we believe that this simplifies the pricing methodology and the derivation of prices"
	• p2245, process map for assigning connections to a customer load group

(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;	• p6, explains Average change in prices for 2021-22. . "Prices for each customer load group will on average reduce for 2021-22 by 13.1% due to the reduction to target revenue." The table quantifies the change for each customer load group.

(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;	• p22, **Allocate costs across customer load groups** section, describes the allocation method for each cost category
	  ○ p22, table, Summary of allocation method
	  ○ p22, We allocate Transmission Cost by applying the proportional contribution to total sub-transmission Network Capacity (kVA) less any non-contributing capacity.
	  ○ p23, Administration costs allocated based on number of ICPs (in each customer load group)
	  ○ p23, We allocate the costs of Operations and Maintenance, Depreciation and Return on Investment based on the share of the replacement cost of assets
	• p6, **Target revenue by customer load group** section. Table – quantifies target revenue by Customer Load Group

(8) State the proportion of target revenue (if applicable) that is collected through each price component as publicly disclosed under clause 2.4.18.	• p10, Table shows aggregate average revenue recovered from all customer load groups through fixed, capacity, and variable price components
2.4.4 Every disclosure under clause 2.4.1	

Information Disclosure Requirement	Reference in this document
above must, if the EDB has a pricing strategy-	
(1) Explain the pricing strategy for the next 5 disclosure years (or as close to 5 years as the pricing strategy allows), including the current disclosure year for which prices are set;	p16, **Future pricing approach** section – key point is "We have a pricing development workplan which sets out a roadmap for evolving our pricing approach and pricing to offer pricing structures which reflect the underlying cost to supply the distribution service desired by our customers."
(2) Explain how and why prices for each consumer group are expected to change as a result of the pricing strategy;	p16, notes "The near-term focus of the workplan is to identify the activities we will undertake to develop a pricing structure which – to the extent practicable – has fixed and variable price components which align to the fixed and variable costs of supply for each customer (load) group."
(3) If the pricing strategy has changed from the preceding disclosure year, identify the changes and explain the reasons for the changes.	No change for 2021/22
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;	p34 **Non-standard contracts section** "EA Networks does not have any customer or group of customers on non-standard contracts."
(b) how the EDB determines whether to use a non-standard contract, including any criteria used;	NA
(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;	NA
(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	NA

Information Disclosure Requirement	Reference in this document
is interrupted. This description must explain— (a) the extent of the differences in the relevant terms between standard contracts and non-standard contracts; (b) any implications of this approach for determining prices for consumers subject to non-standard contracts;	
(3) Describe the EDB's approach to developing prices for electricity distribution services provided to consumers that own distributed generation, including any payments made by the EDB to the owner of any distributed generation, and including the— (a) prices; and (b) value, structure and rationale for any payments to the owner of the distributed generation.	• p26, table of prices available for General customer load group includes GEDG (Export kWh) and GUDG (Generation credit) price codes, each with a $0 rate, ie, no payments/charges • p32, Large generation customer load group describes charges/payments to 4 large DG. "We act in accordance with the requirements of Part 6…". No payments are made following publishing USI list in February 2019
2.4.6 Every EDB must at all times publicly disclose a description of its current policy or methodology for determining capital contributions, including-	p34 "We have separate capital contributions within our New Connections and Extensions Policy, this is available on our website or from our offices". Refer: https://www.eanetworks.co.nz/assets/PDFs/Disclosures/Regulatory/Other/e7d903803e/New-Connections-Extensions-PolicyEA-v2.pdf
1(a) the circumstances (or how to determine the circumstances) under which the EDB may require a capital contribution;	New connections and extensions policy, 22 March 2013 (Capital contribution Policy document), sections 4.2 – 4.7 describe circumstances under which a capital contribution is required (for different types of new connection). Refer: https://www.eanetworks.co.nz/assets/PDFs/Disclosures/Regulatory/Other/e7d903803e/New-Connections-Extensions-PolicyEA-v2.pdf
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;	Capital contribution policy document, sections 4.2 – 4.7 describe how the amount payable is determined, plus Schedule A.

Information Disclosure Requirement	Reference in this document
1(c) the extent to which any policy or methodology applied is consistent with the relevant pricing principles;	• p34 notes "There is a high level of transparency of pricing made available to affected customers in a consistent manner to our general pricing methodology. • New or Modified Connections and Extensions Policy document, p4, notes "Our economic aim is to apply efficient pricing policies which reflect the economic costs of providing our delivery service."
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	New or Modified Connections and Extensions Policy document, p10, notes "Customers are required to make a larger contribution but are also able to minimise their total outlay by selecting the most competitive approved contractor to carry out the extension work."
3) If the EDB has a standard schedule of capital contribution charges, the current version of that standard schedule	New Connections and Extensions Policy document, Schedule A.
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	Process – respond within defined time for any query of charge.

APPENDIX C – Pricing Schedule 2021-22

Customer Group	Price Category Code	Price Category	Count	Code	Description	Notes	Units	Prices from 1st April 2020 (revised 24 February 2021)				Prices from 1st April 2021		
								Distribution	Transmission	Delivery	Discount	Distribution	Transmission	Delivery
General	GS05	General Supply - less than 5 kVA	43	GS05	Un-metered Supplies	Single phase less than 30A	$/con/day	0.5263	0.0000	**0.5263**	0.0518	0.5183	0.0000	**0.5183**
	GS20	General Supply - 20 kVA	15,425	GS20	20 kVA	Maximum of two phase 63A or three phase 32A	$/con/day	0.1500	0.0000	**0.1500**	0.0000	0.1500	0.0000	**0.1500**
	GS50	General Supply - 50 kVA	1,659	GS50	50 kVA	Three phase 33 - 63A	$/con/day	0.3000	0.0000	**0.3000**	0.0000	0.3000	0.0000	**0.3000**
	G100	General Supply - 100 kVA	714	G100	100 kVA	Three phase 64 - 160A	$/con/day	0.6000	0.0000	**0.6000**	0.0000	0.6000	0.0000	**0.6000**
	G150	General Supply - 150 kVA	297	G150	150 kVA	Three phase 161A or greater	$/con/day	0.9000	0.0000	**0.9000**	0.0000	0.9000	0.0000	**0.9000**
			17,120	GUEN	Uncontrolled		$/kWh	0.0673	0.0184	**0.0857**	0.0066	0.0663	0.0113	**0.0776**
			10,199	GCOP	Controlled 16	Controlled Load by Ripple channels 100-00 to 100-11, 103-15 to 103-17	$/kWh	0.0162	0.0000	**0.0162**	0.0016	0.0160	0.0000	**0.0160**
			234	G10N	Night Boost	Controlled Load by Ripple channel 110-56	$/kWh	0.0162	0.0000	**0.0162**	0.0016	0.0160	0.0000	**0.0160**
			1,334	GNEN	Night only	Controlled Load by Ripple channels 110-53, 110-54, 110-55	$/kWh	0.0000	0.0000	**0.0000**	0.0000	0.0000	0.0000	**0.0000**
			153	GEDG	Embedded Generation Export kWh		$/kWh	0.0000	0.0000	**0.0000**	0.0000	0.0000	0.0000	**0.0000**
			-	GUDG	Embedded Generation Generation Credit	Volume is the minimum of Export and Import Uncontrolled Energy	$/kWh	0.0000	0.0000	**0.0000**	0.0000	0.0000	0.0000	**0.0000**
			3	MCRF	Floodlight - Closed		$/fixture/day	0.2863	0.0000	**0.2863**	0.0282	0.2819	0.0000	**0.2819**
			5	MCRU	Under Verandah - Closed		$/fixture/day	0.2520	0.0000	**0.2520**	0.0248	0.2482	0.0000	**0.2482**
Irrigation	ISCH	Irrigation	1,605	ISCH	Connected kW	Value held in Chargeable Capacity	$/kW/day	0.2713	0.1562	**0.4275**	0.0331	0.2653	0.0907	**0.3560**
	ISCF	Irrigation Harmonic Penalty	9	ISCF	Irrigation Harmonic Penalty	Value held in Chargeable Capacity	$/kW/day	0.3713	0.1562	**0.5275**	0.0331	0.3653	0.0907	**0.4560**
			1,614	IUEN	Uncontrolled		$/kWh	0.0000	0.0000	**0.0000**	0.0000	0.0000	0.0000	**0.0000**
	ISCM	Irrigation Managed Trial	1	ISCH	Connected kW	Value held in Chargeable Capacity	$/kW/day	0.2713	0.1562	**0.4275**	0.0331	0.2653	0.0907	**0.3560**
			1	ISMR	Irrigation Managed Rebate	Value held in Chargeable Capacity	$/kW/day	0.0000	-0.1000	**-0.1000**	0.0000	0.0000	-0.1000	**-0.1000**
			1	IUEN	Uncontrolled		$/kWh	0.0000	0.0000	**0.0000**	0.0000	0.0000	0.0000	**0.0000**
Industrial	ICMD	Industrial Supply - kVA	35	ICMD	Anytime Demand kVA		$/kVA/day	0.2656	0.1216	**0.3872**	0.0331	0.2597	0.0700	**0.3297**
			35	IEMD	Uncontrolled		$/kWh	0.0000	0.0000	**0.0000**	0.0000	0.0000	0.0000	**0.0000**
	ICDYMD	Industrial Day Demand	2	ICDYMD	Day Demand kVA		$/kVA/day	0.2656	0.1216	**0.3872**	0.0331	0.2597	0.0700	**0.3297**
			2	ICDYAD	Anytime Demand kVA		$/kVA/day	0.0000	0.0000	**0.0000**	0.0000	0.0000	0.0000	**0.0000**
			2	IEDS	Uncontrolled		$/kWh	0.0000	0.0000	**0.0000**	0.0000	0.0000	0.0000	**0.0000**
	ICDPD	Industrial Peak Demand	7	ICDPD	Peak Demand	Weekdays excl. Public Holidays	$/kVA/day	0.0000	0.1216	**0.1216**	0.0000	0.0000	0.0700	**0.0700**
			7	ICDAM	Anytime Demand		$/kVA/day	0.2656	0.0000	**0.2656**	0.0331	0.2597	0.0000	**0.2597**
			7	ICEN	Uncontrolled		$/kWh	0.0000	0.0000	**0.0000**	0.0000	0.0000	0.0000	**0.0000**
Large Users	LUCM	ANZCO Seafield Plant	1	LUCM	ANZCO Seafield Plant		$/day	707.0529	0.0000	**707.0529**	74.8860	694.2752	0.0000	**694.2752**
			1	LECM	ANZCO Seafield Plant Energy		$/kWh	0.0000	0.0000	**0.0000**	0.0000	0.0000	0.0000	**0.0000**
			1	LMCM	ANZCO Seafield Plant MD		$/kVA/day	0.0000	0.1232	**0.1232**	0.0000	0.0000	0.0759	**0.0759**
	LUPP	Talley's Fairfield Plant	1	LUPP	Talley's Fairfield Plant		$/day	99.1597	0.0000	**99.1597**	10.5023	97.3677	0.0000	**97.3677**
			1	LEPP	Talley's Fairfield Plant Energy		$/kWh	0.0000	0.0000	**0.0000**	0.0000	0.0000	0.0000	**0.0000**
			1	LMPP	Talley's Fairfield Plant MD		$/kVA/day	0.0000	0.1267	**0.1267**	0.0000	0.0000	0.0768	**0.0768**
	LUMH	Mt Hutt Ski Area	1	LUMH	Mt Hutt		$/day	340.3709	0.0000	**340.3709**	36.0497	334.2198	0.0000	**334.2198**
			1	LEMH	Mt Hutt Energy		$/kWh	0.0000	0.0000	**0.0000**	0.0000	0.0000	0.0000	**0.0000**
			1	LMMH	Mt Hutt MD	Weekdays excl. Public Holidays	$/kVA/day	0.0000	0.0902	**0.0902**	0.0000	0.0000	0.0601	**0.0601**
	LUHP	Highbank Pumps	1	LUHP	Highbank Pumps		$/kW/day	0.0489	0.1563	**0.2052**	0.0061	0.0463	0.0912	**0.1375**
			1	LEHP	Highbank Pumps Energy		$/kWh	0.0000	0.0000	**0.0000**	0.0000	0.0000	0.0000	**0.0000**
			1	LMHP	Highbank Pumps MD		$/kVA/day	0.0000	0.0000	**0.0000**	0.0000	0.0000	0.0000	**0.0000**
Generation	LUHB	Highbank	1	LUHB	Highbank		$/day	950.4324	0.0000	**950.4324**	100.6631	933.2564	0.0000	**933.2564**
			1	LEHB	Highbank Energy		$/kWh	0.0000	0.0000	**0.0000**	0.0000	0.0000	0.0000	**0.0000**
			1	LMHB	Highbank MD		$/kVA/day	0.0000	0.0000	**0.0000**	0.0000	0.0000	0.0000	**0.0000**
	LUMO	Montalto	1	LUMO	Montalto		$/day	97.4270	0.0000	**97.4270**	10.3188	95.6663	0.0000	**95.6663**
			1	LEMO	Montalto Energy		$/kWh	0.0000	0.0000	**0.0000**	0.0000	0.0000	0.0000	**0.0000**
			1	LMMO	Montalto MD		$/kVA/day	0.0000	0.0000	**0.0000**	0.0000	0.0000	0.0000	**0.0000**
	LUCD	Cleardale	1	LUCD	Cleardale		$/day	76.1442	0.0000	**76.1442**	8.0647	69.5061	0.0000	**69.5061**
			1	LECD	Cleardale Energy		$/kWh	0.0000	0.0000	**0.0000**	0.0000	0.0000	0.0000	**0.0000**
			1	LMCD	Cleardale MD		$/kVA/day	0.0000	0.0000	**0.0000**	0.0000	0.0000	0.0000	**0.0000**
	LULN	Lavington	1	LULN	Lavington		$/day	19.6069	0.0000	**19.6069**	2.0766	19.2526	0.0000	**19.2526**
			1	LELN	Lavington Energy		$/kWh	0.0000	0.0000	**0.0000**	0.0000	0.0000	0.0000	**0.0000**
			1	LMLN	Lavington MD		$/kVA/day	0.0000	0.0000	**0.0000**	0.0000	0.0000	0.0000	**0.0000**
Street Lighting	MCSL	Street Lighting	2	MCSL	Street lighting		$/fixture/day	0.1906	0.0047	**0.1953**	0.0202	0.1872	0.0035	**0.1907**

General Notes

- Discounts are calculated on consumption from 1st April 2020 to 31st March 2021 and paid (credited) to consumers' power accounts after the end of the financial year (31st March 2021).
- Count is EA Networks' reasonable estimate of the total number of connections within each price category.
- All Prices are GST Exclusive.
- Transmission Prices include recovery of Pass-thru costs (Council Rates and Industry fees)
- Inclusive metering will be billed at the Uncontrolled Price

Irrigation Price category rules

- Minimum chargeable Capacity of 10 kW.
- From 30 October 2013 all new Irrigation connections greater than 20 kW must be on the Irrigation Price category. Existing Irrigation connections greater than 20 kW switched from General to Irrigation Price category will not be switched back.
- Irrigation connections that are less than or equal to 20 kW chargeable have the option to switch between the appropriate General and Irrigation Price category on the condition that they stay on that option for a minimum of 12 months.
- Is a single meter installation.
- Irrigation Charges are Annual charges to recover costs of Assets provided.
- The Irrigation Managed Trial (ISCM) is a closed Price category, no new connections will be accepted.

Industrial Pricing Option Rules

- Minimum 25 kVA demand.
- Industrial connections are all year round operations, i.e. are not seasonal in nature.
- Meters are read monthly.
- Industrial connections require a single meter installation.

*** Interconnection RCPD Credit**

- As per the Electricity Authority decision, Embedded Generation on EA Networks Electrical Network is not eligible to receive avoided cost of transmission payments from 1st October 2019

APPENDIX D - Directors approval

Schedule 17 Certification for Year-beginning Disclosures

Clause 2.9.1

We, Philip John McKendry and Paul Jason Munro, being directors of Electricity Ashburton Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a) the following attached information of Electricity Ashburton Limited prepared for the purposes of clauses 2.4.1, 2.6.1, 2.6.3, 2.6.6 and 2.7.2 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.

c) The forecasts in Schedules 11a, 11b, 12a, 12b, 12c and 12d are based on objective and reasonable assumptions which both align with Electricity Ashburton Limited corporate vision and strategy and are documented in retained records.

Paul Jason Munro

Philip John McKendry

24 March 2020