Pricing Methodology
Electricity Distribution Network

Effective from 1 April 2019

Pursuant to:

Electricity Distribution Information Disclosure Determination 2012 (consolidated April 2018), and; Distribution Pricing Principles and Information Disclosure Guidelines 2010.

Contents

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.

Philip McKendry

Paul Jason Munro

28 March 2019

Background

The purpose of this document is to detail EA Networks Pricing Methodology.

The document is divided into two sections:

1. Updates to Target Revenues, Costs and Consumer consultation for 2019/20.
2. Pricing methodology (established 2015/16) that remains current.

Section 1 provides an overview of the allowable changes under the Default Price Path methodology as well as describing changes to Transmission Costs.

Section 2 details the prevailing Pricing Methodology that was established during 2015/16 and remains current however amended with relevant statistics.

Section 1 - Target Revenues, Costs and Consumer Consultation for 2019/20

Summary of changes: current pricing (2019/20)

EA Networks has reviewed pricing under the Commerce Commissions Default Price Path Methodology (DPP). Under the DPP the company has estimated the allowable Distribution Price change of 2.51% (3.25% including volume movement):

	2018-19	2019-20	Difference
Distribution Revenue $000	$ 35,399	$ 36,551	$ 1,152

Recoverable (Transmission) & Pass-through Costs $000

	2018-19	2019-20	Difference
Rates and Levies	$ 280	$ 434	$ 154
Transpower	$ 6,463	$ 16,690	$ 10,227
ACOT	$ 1,187	$ 179	-$ 1,008
Total	$ 7,930	$ 17,303	$ 9,373

Directors of EA Networks have elected to maintain the prevailing Pricing Methodology.

The additional $10 million of revenue requirement resulted in the following increases to Delivery Prices:

General	10.5%
Industrial	13.4%
Irrigation	39.7%
Major Users	37.7%
Generation	1.3%

Target revenue is expected to increase to **$53.85 million** for 2019/20 financial year ($**43.33** million for 2018/19 Budget).

Target Revenues by Customer Load Group

Customer Load Group	Number of Connections	Revenue estimate $'000
General	17,471	$24,219
Industrial	43	$2,238
Irrigation	1,601	$24,802
Major Users	13	$2,120
Generation	4	$466
Total	19,132	***$53,845***

Target Revenues by Cost Category

Cost Category	Revenue estimate $'000
Recoverable (transmission) and Pass-through	$17,303
Operations and maintenance	$5,740
Administration	$4,777
Depreciation	$9,380
Cost of capital	$16,645
Total	***$53,845***

Recoverable (transmission) and Pass-through

Cost Category	Cost estimate $'000
Connections Costs	$2,152
Interconnection Costs	$14,717
Pass-through costs	$434
Total	***$17,303***

Consumer consultation

During September/October 2017, EA Networks undertook Consumer Consultation (conducted bi-annually). 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 prices and quality of service offered by EA Networks.

Pricing Schedule (2019/20)

EA networks

Pricing Schedule as at 1 April 2019

Customer Group	Price Category Code	Price Category	Count	Code	Description	Notes	Units	2018 - 19 * Disclosure purposes only Distribution	2018 - 19 * Disclosure purposes only Transmission	2018 - 19 Delivery	1st April 2019 Prices * Disclosure purposes only Distribution	1st April 2019 Prices * Disclosure purposes only Transmission	1st April 2019 Prices Delivery
General	GS05	General Supply - less than 5 kVA	42	GS05	Un-metered Supplies	Single phase less than 30A	$/con/day	0.5646	0.0000	**0.5646**	0.5788	0.0000	**0.5788**
	GS20	General Supply - 20 kVA	15,163	GS20	20 kVA	Maximum of two phase 63A or three phase 32A	$/con/day	0.1500	0.0000	**0.1500**	0.1500	0.0000	**0.1500**
	GS50	General Supply - 50 kVA	1,621	GS50	50 kVA	Three phase 33 - 63A	$/con/day	0.3000	0.0000	**0.3000**	0.3000	0.0000	**0.3000**
	G100	General Supply - 100 kVA	681	G100	100 kVA	Three phase 64 - 160A	$/con/day	0.6000	0.0000	**0.6000**	0.6000	0.0000	**0.6000**
	G150	General Supply - 150 kVA	278	G150	150 kVA	Three phase 161A or greater	$/con/day	0.9000	0.0000	**0.9000**	0.9000	0.0000	**0.9000**
				GUEN	Uncontrolled		$/kWh	0.0722	0.0190	**0.0912**	0.0740	0.0276	**0.1016**
				GCOP	Controlled 16	Controlled Load by Ripple channels 100-00 to 100-11, 103-15 to 103-17	$/kWh	0.0174	0.0000	**0.0174**	0.0178	0.0000	**0.0178**
				G10N	Night Boost	Controlled Load by Ripple channel 110-56	$/kWh	0.0174	0.0000	**0.0174**	0.0178	0.0000	**0.0178**
				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**
				GEDG	Embedded Generation Export kWh		$/kWh	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**
				MCRF	Floodlight - Closed		$/fixture/day	0.3072	0.0000	**0.3072**	0.3149	0.0000	**0.3149**
				MCRU	Under Verandah - Closed		$/fixture/day	0.2703	0.0000	**0.2703**	0.2771	0.0000	**0.2771**
Irrigation	ISCH	Irrigation	1,597	ISCH	Connected kW	Value held in Chargeable Capacity	$/kW/day	0.3000	0.0503	**0.3503**	0.3082	0.1814	**0.4896**
	ISCF	Irrigation Harmonic Penalty	12	ISCF	Irrigation Harmonic Penalty	Value held in Chargeable Capacity	$/kW/day	0.4000	0.0503	**0.4503**	0.4082	0.1814	**0.5896**
				IUEN	Uncontrolled		$/kWh	0.0000	0.0000	**0.0000**	0.0000	0.0000	**0.0000**
				ISFD	Filter installation Discount	One-off Discount payment when Filter equipment is installed	$/VSD kW	-80.0000	0.0000	**-80.0000**	-80.0000	0.0000	**-80.0000**
Industrial	ICMD	Industrial Supply - kVA	40	ICMD	Anytime Demand kVA		$/kVA/day	0.2913	0.1400	**0.4313**	0.3058	0.1833	**0.4891**
				IEMD	Uncontrolled		$/kWh	0.0000	0.0000	**0.0000**	0.0000	0.0000	**0.0000**
	ICDYMD	Industrial Day Demand	1	ICDYMD	Day Demand kVA		$/kVA/day	0.2913	0.1400	**0.4313**	0.3058	0.1833	**0.4891**
				ICDYAD	Anytime Demand kVA		$/kVA/day	0.0000	0.0000	**0.0000**	0.0000	0.0000	**0.0000**
				IEDS	Uncontrolled		$/kWh	0.0000	0.0000	**0.0000**	0.0000	0.0000	**0.0000**
	ICDPD	Industrial Peak Demand	4	ICDPD	Peak Demand	Weekdays excl. Public Holidays	$/kVA/day	0.0234	0.1482	**0.1716**	0.0000	0.1833	**0.1833**
				ICDAM	Anytime Demand		$/kVA/day	0.2679	-0.0082	**0.2597**	0.3058	0.0000	**0.3058**
				ICEN	Uncontrolled		$/kWh	0.0000	0.0000	**0.0000**	0.0000	0.0000	**0.0000**
Large Users	LUCM	CMP	1	LUCM	CMP		$/day	665.1669	0.0000	**665.1669**	665.1669	0.0000	**665.1669**
				LECM	CMP Energy		$/kWh	0.0000	0.0000	**0.0000**	0.0000	0.0000	**0.0000**
				LMCM	CMP MD		$/kVA/day	0.0227	0.1489	**0.1716**	0.0227	0.1833	**0.2060**
	LUPP	Silver Fern Farms	1	LUPP	Silver Fern Farms		$/day	89.1084	0.0000	**89.1084**	89.1084	0.0000	**89.1084**
				LEPP	Silver Fern Farms Energy		$/kWh	0.0000	0.0000	**0.0000**	0.0000	0.0000	**0.0000**
				LMPP	Silver Fern Farms MD		$/kVA/day	0.0227	0.1489	**0.1716**	0.0227	0.1833	**0.2060**
	LUMH	Mt Hutt Ski Area	1	LUMH	Mt Hutt		$/day	354.0878	0.0000	**354.0878**	354.0878	0.0000	**354.0878**
				LEMH	Mt Hutt Energy		$/kWh	0.0000	0.0000	**0.0000**	0.0000	0.0000	**0.0000**
				LMMH	Mt Hutt MD	Weekdays excl. Public Holidays	$/kVA/day	0.0227	0.1489	**0.1716**	0.0227	0.1833	**0.2060**
	LUHP	Highbank Pumps	1	LUHP	Highbank Pumps		$/kW/day	0.0498	0.0503	**0.1001**	0.0555	0.1814	**0.2369**
				LEHP	Highbank Pumps Energy		$/kWh	0.0000	0.0000	**0.0000**	0.0000	0.0000	**0.0000**
				LMHP	Highbank Pumps MD		$/kVA/day	0.0000	0.0000	**0.0000**	0.0000	0.0000	**0.0000**
Generation	LUHB	Highbank	1	LUHB	Highbank		$/day	1,058.5216	0.0000	**1,058.5216**	1,058.5216	0.0000	**1,058.5216**
				LEHB	Highbank Energy		$/kWh	0.0000	0.0000	**0.0000**	0.0000	0.0000	**0.0000**
				LMHB	Highbank MD		$/kVA/day	0.0000	0.0000	**0.0000**	0.0000	0.0000	**0.0000**
				LTHB	* Highbank Interconnection RCPD Credit		$/day	0.0000	-3,064.3092	**-3,064.3092**	0.0000	-813.1775	**-813.1775**
				LHHB	Highbank HVDC Pass-thru		$/day	0.0000	0.0000	**0.0000**	0.0000	0.0000	**0.0000**
	LUMO	Montalto	1	LUMO	Montalto		$/day	92.4395	0.0000	**92.4395**	108.5070	0.0000	**108.5070**
				LEMO	Montalto Energy		$/kWh	0.0000	0.0000	**0.0000**	0.0000	0.0000	**0.0000**
				LMMO	Montalto MD		$/kVA/day	0.0000	0.0000	**0.0000**	0.0000	0.0000	**0.0000**
				LHMO	Montalto HVDC Pass-thru		$/day	0.0000	0.0000	**0.0000**	0.0000	0.0000	**0.0000**
	LUCD	Cleardale	1	LUCD	Cleardale		$/day	84.8038	0.0000	**84.8038**	84.8038	0.0000	**84.8038**
				LECD	Cleardale Energy		$/kWh	0.0000	0.0000	**0.0000**	0.0000	0.0000	**0.0000**
				LMCD	Cleardale MD		$/kVA/day	0.0000	0.0000	**0.0000**	0.0000	0.0000	**0.0000**
				LTCD	* Cleardale Interconnection RCPD Credit		$/day	0.0000	-90.5173	**-90.5173**	0.0000	-119.7801	**-119.7801**
				LHCD	Cleardale HVDC Pass-thru		$/day	0.0000	0.0000	**0.0000**	0.0000	0.0000	**0.0000**
	LULN	Lavington	1	LULN	Lavington		$/day	21.8367	0.0000	**21.8367**	21.8367	0.0000	**21.8367**
				LELN	Lavington Energy		$/kWh	0.0000	0.0000	**0.0000**	0.0000	0.0000	**0.0000**
				LMLN	Lavington MD		$/kVA/day	0.0000	0.0000	**0.0000**	0.0000	0.0000	**0.0000**
				LTLN	* Lavington Interconnection RCPD Credit		$/day	0.0000	-97.9980	**-97.9980**	0.0000	-47.5773	**-47.5773**
				LHLN	Lavington HVDC Pass-thru		$/day	0.0000	0.0000	**0.0000**	0.0000	0.0000	**0.0000**
Street Lighting	MCSL	Street Lighting	9	MCSL	Street lighting		$/fixture/day	0.2333	0.0000	**0.2333**	0.2123	0.0210	**0.2333**

All Prices are GST Exclusive

General Notes:

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:

1. Minimum chargeable Capacity of 10 kW.
2. 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.
3. 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.
4. Is a single meter installation.
5. Irrigation Charges are Annual charges to recover costs of Assets provided.

*** Interconnection RCPD Credit**

As per the Electricity Authority Draft consultation paper, it is expected that Embedded Generation on EA Networks Electrical Network will not be eligible to qualify to receive avoided cost of transmission payments from 1st October 2019:
www.ea.govt.nz/dmsdocument/23949-consultation-paper-draft-dg-lists-for-the-uni-and-usi

Industrial Pricing Option rules:

1. Minimum 25 kVA demand.
2. Are all year round operations, i.e. are not seasonal in nature.
3. Meters are read monthly.
4. Is a single meter installation.

Section 2 – Pricing methodology (established 2015/16) - carried forward

Background

The purpose of this section is to outline EA Networks methodology for setting prices and to disclose our current pricing derived from that methodology. This document is designed to be read by customers, retailers and any other interested parties.

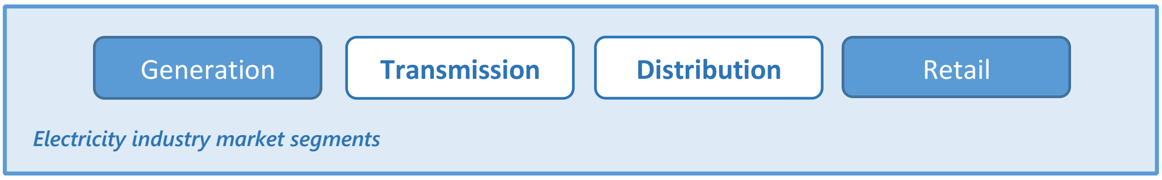
In this document we summarise our pricing methodology by first providing a high-level overview of our approach to pricing. This is aimed to simplify the information presented and provide quick access to important information. As the reader continues the document will provide increasing levels of detail so that specific aspects can be understood in more depth as may be required by the reader.

The content of this document is designed to align to the disclosure requirements set out in the *Electricity Distribution Information Disclosure Determination 2012 (consolidated in 2015) – 24 March 2015*, in particular section 2.4. We have also used the *Distribution Pricing Principles and Information Disclosure Guidelines 2010* to ensure coverage of information disclosure expectations.

Definitions

Assets	The hardware, equipment or plant that is part of our electricity distribution network.
ACOT	Avoidable Cost of Transmission
Controlled Energy	Electricity supply that we temporarily cease supply when required, typically during periods of high load. It is most commonly water heating load.
Customer	An end user that 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.
HVDC	High Voltage Direct Current. This is Transpower's inter-island link between the North and South Islands.
ICP	Installation Control Point. This is the isolation point where a customer connects to the distribution network and where the retailers metering is located.
kWh	Kilowatt-hour. The measure of electricity consumption that retail electricity consumption is measured.
kVA	Kilovolt Ampere. We use this to describe capacity of connections.
Retailer	The entity that charges customers for their electricity usage.
Target Revenue	The forecasted annual revenue that 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, and recoverable costs including regulatory levies and local authority rates.

What our pricing covers



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. We take electricity from the local Grid Exit Point (GXP) operated by Transpower and distribute this within our region – this spans generally from the Rangitata River to the Rakaia River, and from the East Coast to the High Country.

It is Transpower's role to deliver electricity up and down the length of New Zealand (*Transmission)* taking energy from the *Generation* companies. Transpower hand-over within each region to the relevant Distribution Company via a number of GXPs. There are 29 regional Distribution Companies operating in New Zealand.

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 wraps all costs from the different market segments into one invoice. As such, despite end users seeing only one charge, the four participants' costs and margins are included in that charge.

Our pricing (that is charged to Electricity Retailers) covers both *Transmission* and *Distribution* 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* whilst also noting how we deal with transmission costs which are ultimately included in our final prices to retailers.

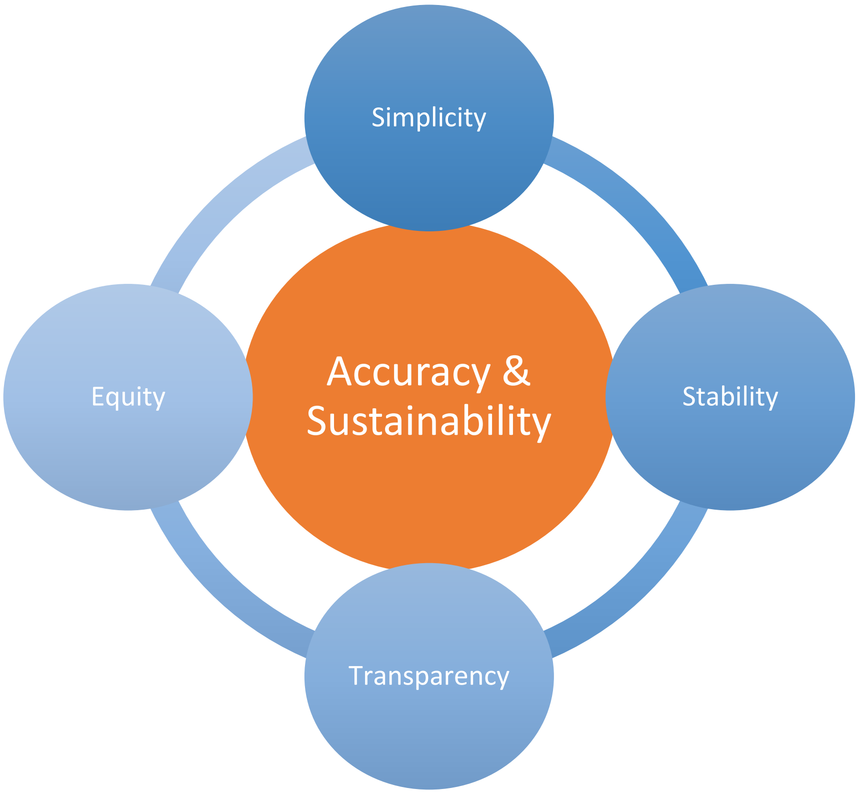
Open access network

Our charges are passed on to retailers that use our network to provide electricity to end users. Retailers that wish to sell electricity to end users within our network area must sign a Use of Systems Agreement (UoSA) with EA Networks. 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. We do not have differential prices, service targets or operational procedures for each individual retailer. Whilst this keeps things simple, it also ensures an equal playing field and should allow greater competition within the retail sector.

Our approach to 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 fairest way that we can. The external view considers the wider market including the regulatory framework that we work within.

Internal perspective

EA Networks is 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. 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.

Overview of our pricing methodology

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

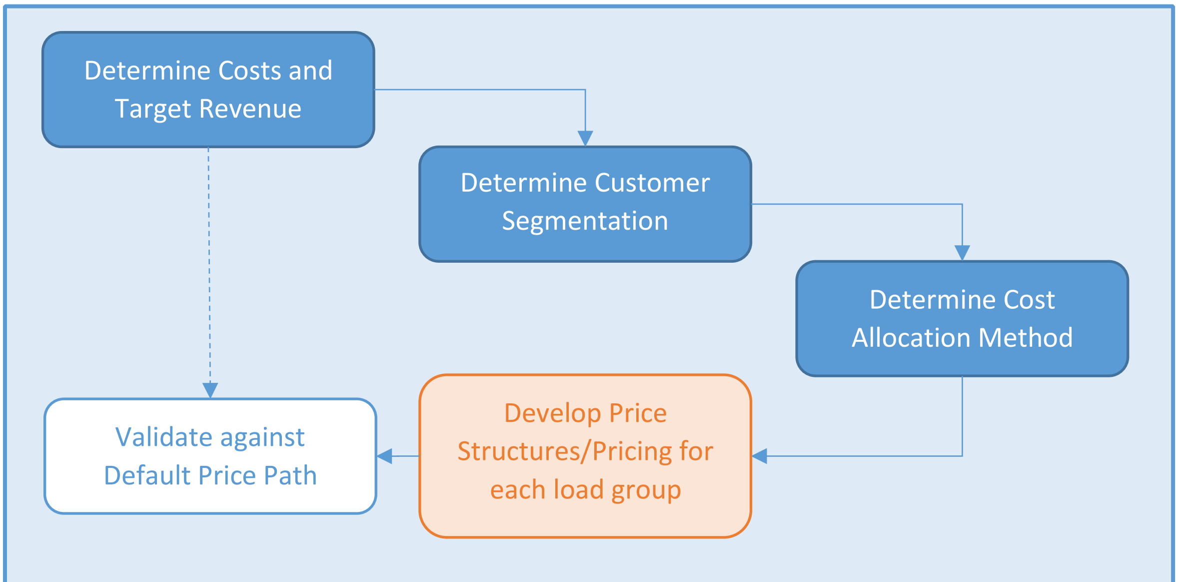
Many of the costs that we recover through pricing are shared across all users of the electricity distribution system. In many cases it is not possible nor practical to attribute costs to a specific user or group of users. In general, shared assets and shared costs are allocated proportionally across 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)

The following diagram is an overview of our approach to determine electricity distribution network pricing (distribution pricing) which is passed-on to Retailers and ultimately end user customers.



Overview of Pricing Methodology

Costs and target revenue

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;

- Transmission
- Operations and maintenance
- Administration
- Depreciation
- Cost of capital (return on investment)

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

Transmission, operations and maintenance, administration and depreciation costs are the budgeted expenses we incur for each of those areas. We use historic financial information and known changes (e.g. staff numbers changing affecting salaries and wages) to derive trends for the next financial year to accurately forecast what these costs will be.

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 *Allowable Distribution 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 and depreciation) with the difference being our Cost of Capital.

Target Revenue is the sum of Allowable Distribution Revenue plus Transmission and other Pass-through costs.

At all times our Distribution Revenue (excludes Transmission and Pass thru Costs) is compared with 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 commencing 1st April 2019 our Target Revenue is **$ 53.85 million**.

The aim of our pricing methodology is to recover this total cost. This is summarised in the five key areas as follows;

Cost Category	Revenue estimate $'000
Transmission	$17,303
Operations and maintenance	$5,740
Administration	$4,777
Depreciation	$9,380
Cost of capital	$16,645
Total	***$53,845***

Customer segmentation

Segmentation of the end user customer base is essential to the development of pricing. It 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.*

We review the different types of connections made to our network and the nature of these connections. We focus on grouping customers 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 approach is referred to as "beneficiary pays" where identifiable assets and costs are charged only to those that use them.

Once customers 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)
- Major Users
- Generation

Whilst 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).*

Cost allocation methodology

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 (beneficiary pays). 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
Transmission	Network capacity (kVA)
Distribution costs:	
Operations and maintenance	Replacement cost of allocated assets
Administration	Number of connections (ICP's)
Depreciation	Replacement cost of allocated assets
Cost of capital (return on investment)	Replacement cost of allocated assets

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.

Interconnection Costs, which drive most of our Transmission Costs, recover the cost of Interconnection Assets i.e. Transpower Lines. As the assets are also used to supply other Lines companies, these 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.

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

Transmission Costs for 2019/20 total $17.303 million. This is comprised of;

- Connections Costs + Pass-throughs $ 2.59 million
- Interconnection Costs $14.71 million
- Total $17.30 million

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.

Other 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 1.

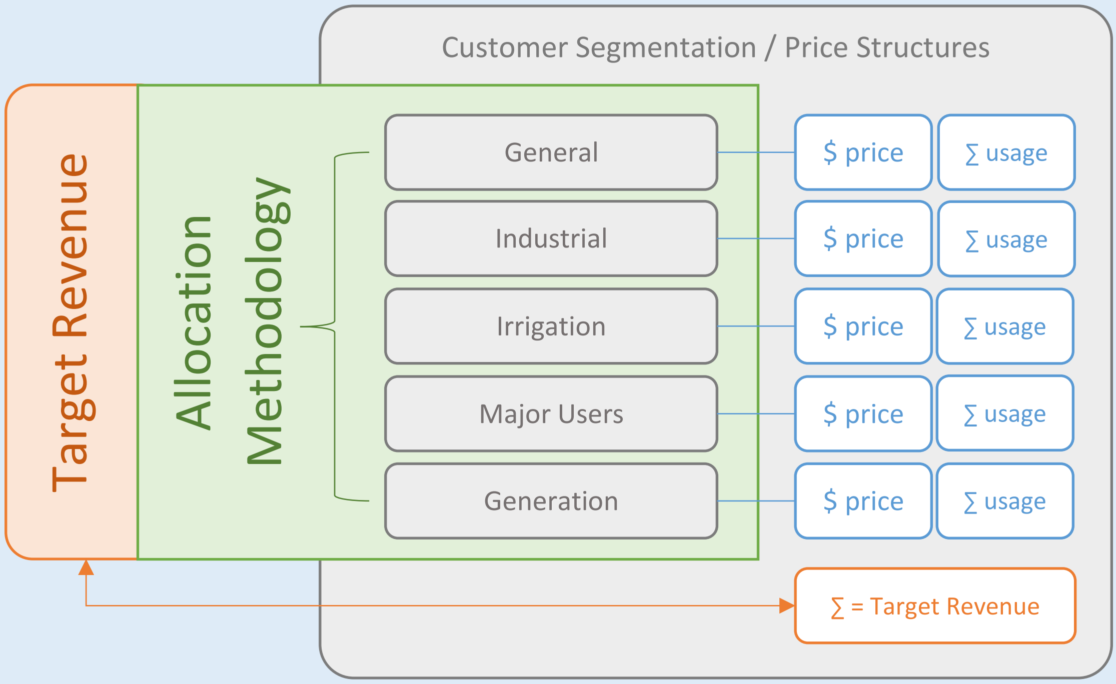
The secondary allocator for the residual Total Asset pool is network capacity (kVA), i.e. a proportional allocation across all load groups based on connection capacity. We believe that this is the best proxy for allocating shared assets fairly to each Customer Load Group. Network capacity is before diversity demand at the medium voltage bus based on anytime maximum demand. Again a summary can be seen in Appendix 1 that shows result of assets allocated to each Customer Load Group.

Summary of our pricing methodology

By applying the Allocation Methodology across each Customer Load Group we can allocate Target Revenue across the various segments. This is summarised as follows;

FY2019/20	Customer Load Group	Number of Connections	Revenue estimate $'000
	General	17,471	$24,219
	Industrial	43	$2,238
	Irrigation	1,601	$24,802
	Major Users	13	$2,120
	Generation	4	$466
	Total	19,132	***$53,845***

The following diagram illustrates how the three areas discussed in summary above (target revenue, customer segmentation and cost allocation) link together to form our pricing methodology;



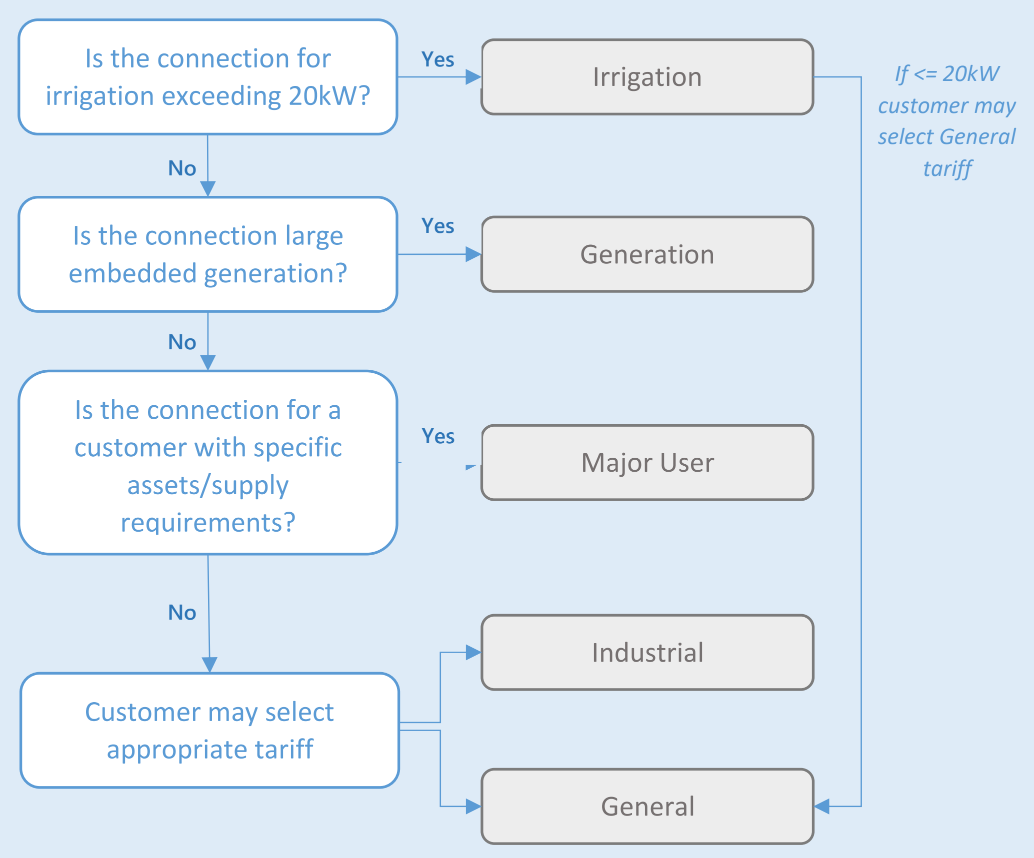
Overview of Cost Allocation Methodology

Pricing methodology customer segment detail

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.

Your customer segment

We apply the following generic approach to determine which customer segment 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 their 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

Number of customers	17,471
Segment target revenue	$24.22 million

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 category are charged based on the maximum capacity of their supply (size of their fusing) charged in $/day and 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.

The rationale for segmenting this way is that our costs are largely driven by the line/service capacity – that is, as connections increase in size, our costs rise. In addition, by having controllable load we can also manage our costs more efficiently.

It is irrelevant to us whether the customer is 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

Fixed charge

The General segment has various sub-groups to provide flexibility and choice to the customer. To comply with Low User regulations (refer to page 29) we offer a standard price at $0.15 fixed rate per day fixed rate (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.

Variable 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 development 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 simply 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

Industrial

Number of customers	43
Segment target revenue	$2.24 million

Mid-Canterbury is largely a rural economy. The industrial sector is small (less than fifty from our segmentation) but has specific electricity supply requirements. This price group is not available to any seasonal supply customers such as irrigation.

An Industrial customer has the choice to switch between General and Industrial. The Industrial prices offer the customer the ability to cap their line charges by controlling their energy use based on maximum demand whereas the variable component within the General price may add uncertainty to their pricing (i.e. the more they use the more they are charged). All Industrial connections must have a Time of Use Meter installed to record Maximum Demand.

Price calculation

Fixed charge

There is no fixed charge for this customer segment, it is entirely based on maximum demand as controlled by the customer.

Variable charge

All revenue derived from the Industrial segment is from the maximum demand component (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.

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

Irrigation

Number of customers	1,601
Segment target revenue	$24.80 million

The irrigation price segment 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). These connections typically create a seasonal load unlike other energy users that have a load profile spanning the calendar year. The resulting specific load profiles and cost drivers require them to be categorised separately.

Irrigation by its very nature is seasonal. The season typically commences during September/October and ends around March. In addition to being seasonal it is also entirely weather dependent. An irrigator will only be used when water is required – 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.

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 based on maximum demand availability.

Because of this unique load and specific consumer requirements, we price our irrigation price based on maximum capacity, since usage is irrelevant to our cost divers. To do this we apply a fixed daily charge spread across the financial year.

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 our 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 price 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 this 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 becomes compliant with our revised standard. This discount is based on the cumulative VSD load that is mitigated. However, evidence of costs to become compliant must be provided and the company will only pay the lower of the entitlement or actual costs incurred. The credit is paid via the electricity retail account associated with the affected ICP.

To qualify for this price a customer must have a non-filtered VSD, installed prior to June 2009 that exceeds 20kW. All affected customers were identified by our inspectors and contacted directly regarding their specific requirements to remain compliant with our standards.

A Differential Price has been established that effectively penalises those irrigation connections that remain non—compliant after September 2017. The differential price adds $0.10 per kW over and above the prevailing Irrigation price rate (ISCH).

This programme is complete and we will take steps to remove this price in coming periods. However, the Differential Price will remain for all non-compliant sites.

More information regarding this standard can be found at www.eanetworks.co.nz/Power/Harmonics.asp

Prices available

Price Code	***Description***	***Units***
ISCH	Irrigation – Connected kW	$/kW/day
ISCF	Irrigation Harmonic Penalty	$/kW/day
ISFD	Irrigation – Filter Installation Discount	$/VSD kW

Major Users

Number of customers	13
Segment target revenue	$2.24 million

Major Users (or Large Users) typically have 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 Major 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 both Major Users and our company benefit from this direct contact so that the specific requirements of the customer can be meet. They are generally atypical users that have bespoke supply requirements and it is important that we meet their requirements wherever possible.

Fixed charge

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 Major Users with 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.

Variable charge

We make a variable charge available to Major Users, charged in $/kWh or $/kVA/day. 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-week days between 11pm and 7am).*

Generally, we charge Major Users 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

Number of customers	4
Segment target revenue	$0.46 million

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.

Presently we have four large embedded Generators operating on our electricity distribution network; Highbank, Montalto, Cleardale and Lavington. As with Major Users we explain electricity supply charges directly with these customers due to the bespoke nature of their requirements.

Allowance is made for variable cost pass-through but these rates are presently set to zero. We also provide pass-through of the fixed monthly credit for interconnection savings and HVDC charges.

Price calculation

Large distributed generation (>10kW)

When pricing for large embedded 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.

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), and;
- Savings of the interconnection costs, and;
- Loss & Constraint Excess Generation Payments.

The interconnection savings, measured from the half-hourly metering is shared between ourselves and the distributed generator.

As per Electricity Authority decision of 5th February 2019, embedded generation on our Network will 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.

Feedback from these surveys continues to indicate that customers are happy with the current prices and quality of service offered by EA Networks.

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[1] 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).

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.

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

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 connection required 100 metres of additional overhead lines to reach the ICP, the customer would pay for the cost of this new line and the related poles. 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 discretion, elect to pay a dividend to shareholders in lien of any discount or rebate.

Consistency with Electricity Authority pricing principles

The Electricity Authority has established Pricing Principles[2] 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 is consistent with the principles established by the Electricity Authority.

PRICING PRINCIPLES

(a) PRICES ARE TO SIGNAL THE ECONOMIC COSTS OF SERVICE PROVISION, BY:

(i) BEING SUBSIDY FREE (EQUAL TO OR GREATER THAN INCREMENTAL COSTS, AND LESS THAN OR EQUAL TO STANDALONE COSTS), EXCEPT WHERE SUBSIDIES ARISE FROM COMPLIANCE WITH LEGISLATION AND/OR OTHER REGULATION;

[2] Distribution Pricing Principles and Information Disclosure Guidelines, prepared by the Electricity Authority, February 2010.

(ii) *HAVING REGARD, TO THE EXTENT PRACTICABLE, TO THE LEVEL OF AVAILABLE SERVICE CAPACITY; AND*

(iii) *SIGNALLING, TO THE EXTENT PRACTICABLE, THE IMPACT OF ADDITIONAL USAGE ON FUTURE INVESTMENT COSTS.*

Readers should be cognisant that electricity distribution pricing forms only a part of the total cost of electricity as incurred by end users. As such, whilst we endeavour to provide price signals to the market our relationship with end user customers is indirect.

The electricity distribution network by its very nature consists of assets with significant capacity. When building new capacity, we take account of forecast growth potential. That is, we will build new network with additional capacity above what is required at the time. To do so there must be sufficient evidence to suggest additional future demand will require this capacity.

This makes a lot of sense as the marginal cost of building greater capacity is generally significantly lower than having to upgrade in the future. Economies of scale ex ist and we take advantage of these for the long run benefit of our customers.

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 7oo 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).

We signal the level of available capacity through prices. Some customers simply 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.

At present we do not apply time of use (TOU) pricing signals. It is our view that the combination of fixed charging, variable charging and controlled load charging provides the appropriate level of signalling to the end user customer regarding the capacity within the electricity distribution network.

PRICING PRINCIPLES (CONTINUED)

(b) *WHERE PRICES BASED ON 'EFFICIENT' INCREMENTAL COSTS WOULD UNDER-RECOVER ALLOWED REVENUES, THE SHORTFALL SHOULD BE MADE UP BY SETTING PRICES IN A MANNER THAT HAS REGARD TO THE CONSUMERS' DEMAND RESPONSIVENESS, TO THE EXTENT PRACTICABLE.*

Our differentiated Customer Load Groups and related prices are designed to have regard to an end user customers demand responsiveness. This is achieved by having a range of prices that better reflect usage types at a more granular level, varying the level of fixed versus variable charging. From this we are better able to provide pricing suitable to the customer's needs and demand responsiveness.

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.

Prices are differentiated with respect to connection size with the daily fixed fee rising in-line with the increased size of the connection. We consider that 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 charge with no variable component. This removes price volatility that could result due to the unpredictability of load and usage which would result from a purely variable charge.

PRICING PRINCIPLES (CONTINUED)

(c) PROVIDED THAT PRICES SATISFY (A) ABOVE, PRICES SHOULD BE RESPONSIVE TO THE REQUIREMENTS AND CIRCUMSTANCES OF STAKEHOLDERS IN ORDER TO:

(i) DISCOURAGE UNECONOMIC BYPASS;

(ii) ALLOW FOR NEGOTIATION TO BETTER REFLECT THE ECONOMIC VALUE OF SERVICES AND ENABLE STAKEHOLDERS TO MAKE PRICE/QUALITY TRADE-OFFS OR NON-STANDARD ARRANGEMENTS FOR SERVICES; AND

(iii) WHERE NETWORK ECONOMICS WARRANT, AND TO THE EXTENT PRACTICABLE, ENCOURAGE INVESTMENT IN TRANSMISSION AND DISTRIBUTION ALTERNATIVES (E.G. DISTRIBUTED GENERATION OR DEMAND RESPONSE) AND TECHNOLOGY INNOVATION.

We have significant purchasing power and the benefit of this is passed through in the form of our final asset value. As pricing is controlled by the Default Price Path regime this flows through to our pricing. The prices charged to access the distributed electricity system compete well against other forms of energy (such as distributed generation through photovoltaics or diesel generators). This discourages the uneconomic bypass of the network for energy needs.

However, alternative sources of energy are available in the market today. Where the incremental cost of providing electricity supply to a customer is greater than the economic value the customer places on that supply, we will not provide services.

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).

Customers are encouraged to opt for demand response supply through our variable rate controlled load prices. These prices provide a significantly reduced rate compared to the uncontrolled variable rate.

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

PRICING PRINCIPLES (CONTINUED)

(d) DEVELOPMENT OF PRICES SHOULD BE TRANSPARENT, PROMOTE PRICE STABILITY AND CERTAINTY FOR STAKEHOLDERS, AND CHANGES TO PRICES SHOULD HAVE REGARD TO THE IMPACT ON STAKEHOLDERS.

Our pricing is transparent in that we make publicly available this Pricing Methodology. In addition, specific tables that detail Customer Load Groups, prices, pricing and related statistical information is made available on our website. Annually we publish our pricing in local newspapers to further make our pricing, and the development of prices transparent.

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 we will 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 connect kW (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. Variable charging would, for this load group, result in volatile pricing.*

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. The board then take a holistic approach to determining the final change (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.

PRICING PRINCIPLES (CONTINUED)

(e) DEVELOPMENT OF PRICES SHOULD HAVE REGARD TO THE IMPACT OF TRANSACTION COSTS ON RETAILERS, CONSUMERS AND OTHER STAKEHOLDERS AND SHOULD BE ECONOMICALLY EQUIVALENT ACROSS RETAILERS.

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 Use of Systems Agreement is open access and all retailers largely share the same terms and conditions. Specifically, all retailers have access to the same prices and no retailer incurs differential pricing of any kind.

- END -

Appendix 1 - Pricing Allocation Model (summary)

	Load Group			LV Connections	MV Connections		Major Users					Generation				Total
	Customer Group			**General**	**Industrial**	**Irrigation**	**Mt Hutt**	**Silver Fern Farms**	**Canterbury Meat Packers**	**Highbank Pumps**	**Street lighting**	**Highbank**	**Montalto**	**Cleardale**	**Lavington**	
*** Statistics**	Expected Average Customer Base			17,471	43	1,601	1	1	1	1	9	1	1	1	1	19,132
	Energy GWh	Uncontrolled		222.3	56.5	176.0	2.2	5.1	35.0	5.7	-	-	-	-	-	502.8
		Controlled	Off-peak	32.8	-	-	-	-	-	-	-	-	-	-	-	32.8
			Night	5.3	-	-	-	-	-	-	-	-	-	-	-	5.3
			UV/Flood lighting	-	-	-	-	-	-	-	1.7	-	-	-	-	1.7
		Generation		0.3	-	-	-	-	-	-	-	122.9	10.5	4.0	3.1	140.7
		Total		260.7	56.5	176.0	2.2	5.1	35.0	5.7	1.7	122.9	10.5	4.0	3.1	683.4
	Measured Demand - kVA			-	12,683	138,272	997	1,195	5,801	9,600	387	22,554	1,586	841	472	
	Load Factor			0.32	0.51	0.15	0.25	0.49	0.70	0.07	0.52	0.63	0.76	0.54	0.76	
	Sub-Transmission Transmission Capacity			91,851	12,565	138,272	997	1,195	5,801	9,600	387	22,554	1,586	841	472	286,120
	Network Capacity			91,851	12,683	138,272	997	1,195	5,801	9,600	387	22,554	1,586	841	472	286,239
Allocation	$000	Transmission	Connection + pass-thrus	914	125	1,375	10	12	58	95	4	-	-	-	-	2,593
			Interconnection	5,183	709	7,803	56	67	327	542	22	-	-	-	-	14,710
		Subtransmission		433	60	664	5	10	36	46	3	-	-	-	-	1,258
		Zone Substations		1,378	192	2,112	16	32	-	147	9	-	-	-	-	3,886
		Distribution Lines		3,439	483	5,273	-	-	-	-	22	-	-	-	-	9,217
		Distribution Switchgear		2,760	388	4,231	-	-	-	-	18	-	-	-	-	7,397
		Distribution Substations		1,902	267	2,916	-	-	-	-	12	-	-	-	-	5,097
		LV Lines		3,830	-	-	-	-	-	-	-	-	-	-	-	3,830
		LV Street Lights		-	-	-	-	-	-	-	195	-	-	-	-	195
		Other System Fixed Assets		18	3	27	0	0	1	2	0	5	0	0	0	58
		Dedicated	Mt Hutt	-	-	-	116	-	-	-	-	-	-	-	-	116
			CMP	-	-	-	-	-	254	-	-	-	-	-	-	254
			Highbank	-	-	-	-	-	-	-	-	382	-	-	-	382
			Montalto	-	-	-	-	-	-	-	-	-	40	-	-	40
			Cleardale	-	-	-	-	-	-	-	-	-	-	31	-	31
			Lavington	-	-	-	-	-	-	-	-	-	-	-	8	8
		Total		19,857	2,227	24,402	204	122	676	832	284	387	40	31	8	49,068
		Adminstration		4,362	11	400	-	-	-	-	2	-	-	-	-	4,777
		Total Revenue		24,219	2,238	24,802	204	122	676	832	286	387	40	31	8	53,845
Summary	$000	Transmission		6,097	834	9,178	66	79	385	637	26	-	-	-	-	17,303
		Operation and Maintenance		2,532	252	2,751	23	4	41	35	31	59	7	4	1	5,740
		Administration		4,362	11	400	-	-	-	-	2	-	-	-	-	4,777
		Depreciation		4,137	412	4,495	38	7	67	57	51	96	12	7	1	9,380
		Cost of Capital		7,091	729	7,978	77	32	183	103	176	232	21	20	6	16,645
		Total Revenue		24,219	2,238	24,802	204	122	676	832	286	387	40	31	8	53,845

* 2017-18 Quantities