Pricing Methodology
Electricity Distribution Network

Effective from 1 April 2015

Pursuant to:

Electricity Distribution Information Disclosure Determination 2012, and;

Distribution Pricing Principles and Information Disclosure Guidelines 2010.

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Directors approval

Schedule 17 Certification for Year-beginning Disclosures

Clause 2.9.1

We, John Bruce Tavendale and Gary Richard Leech, being directors of Electricity Ashburton Limited, trading as 'EA Networks' certify that, having made all reasonable enquiry, to the best of our knowledge:-

a) The following attached information of EA Networks prepared for the purposes of clauses 2.4.1, 2.6.1, 2.6.3, 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 standard.

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

John Bruce Tavendale

Gary Richard Leech

31 March 2015

Definitions

Assets	The hardware, equipment or plant that is part of our electricity distribution network.
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.
Tariff	The product that a customer uses to access the electricity distribution network.
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.

Background

The purpose of this document 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*, in particular section 2.4. We have also used the *Distribution Pricing Principles and Information Disclosure Guidelines* to ensure coverage of information disclosure expectations.

Summary of changes: current pricing (2015/16)

EA Networks has reviewed pricing for the electricity distribution network based on the methodology described within this document. Under the Commerce Commissions Default Price Path Methodology (DPP), EA Networks Target Revenue could increase by 3.3% to an estimated $40.5 million. Instead, EA Networks board of directors elected to maintain all tariff prices at the prior year's levels (i.e. unchanged). On a like-for-like basis this results in a Revised Target Revenue of $39.2 million, $1.3 million less than the DPP would allow.

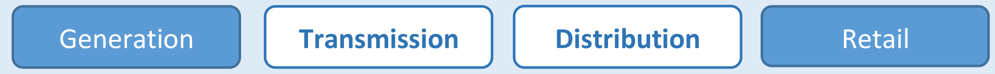
However, Target Revenue is calculated using quantities from the 2013/14 year (i.e. Q-2). Allowing for volume growth and applying this to current rates our Budget Revenue for 2015/16 financial year is **$41.96 million**.

Whilst keeping tariff prices unchanged, there have been underlying movements in the components that make-up Distribution Pricing, specifically Transmission costs and Distribution costs. The former have reduced whilst Distribution prices have increased by an equal and off-setting amount. Combined, total prices applied to each tariff remain unchanged year-on-year.

In addition, pass-through costs, specifically; local authority rates and regulatory levies have now been included in our Transmission rates.

There have been no other changes to prices, pricing methodology or the tariff structure.

What our pricing covers



Electricity industry market segments

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, in reality 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.

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.

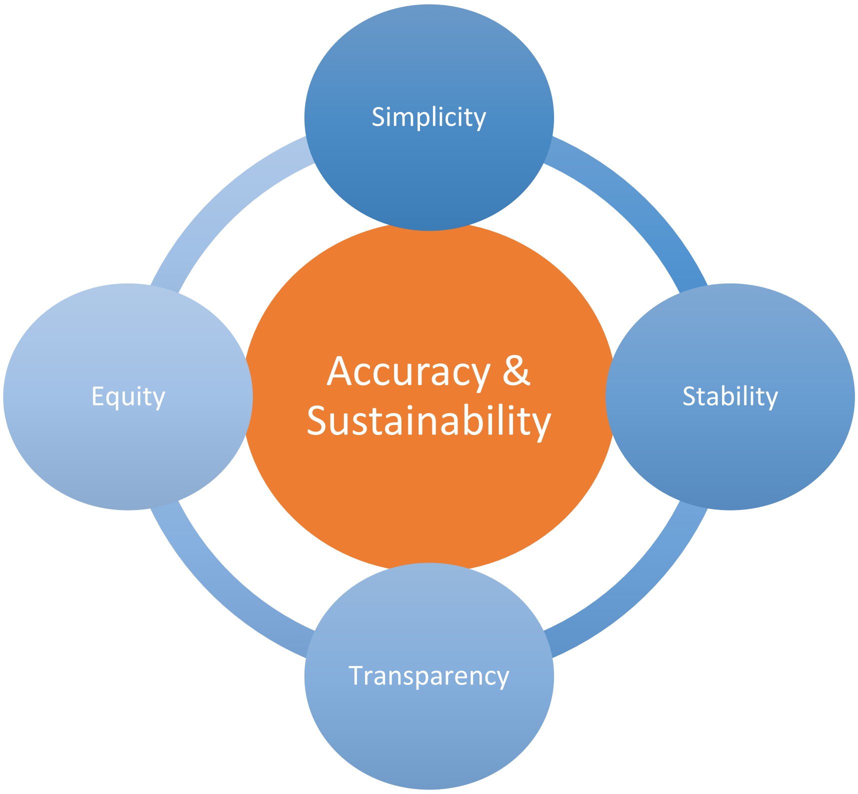
Open access network

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 in particular 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 and commercial constraints.

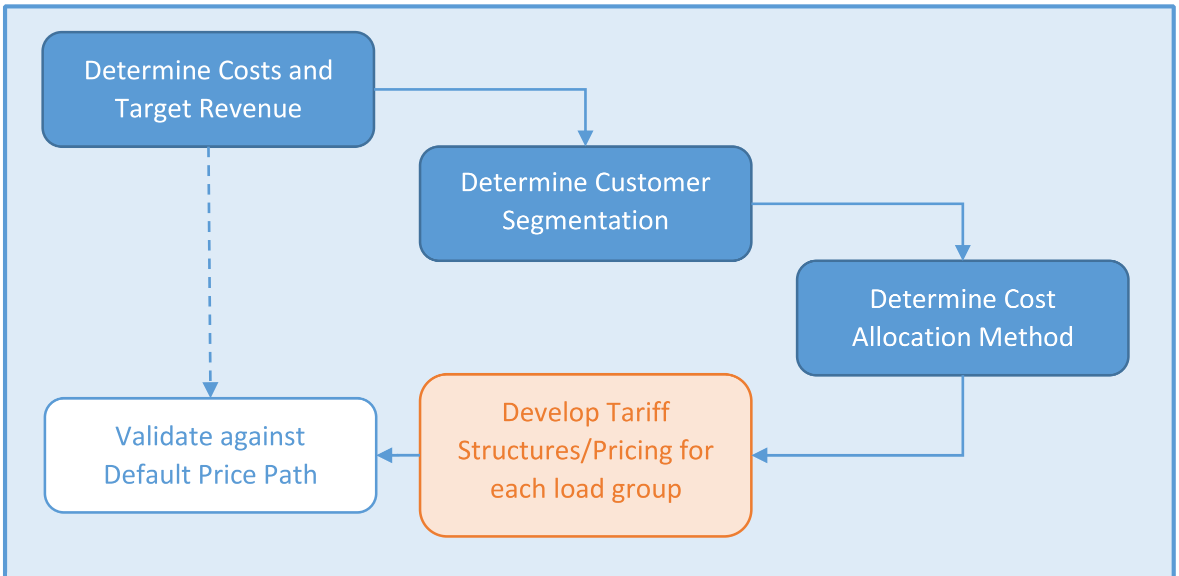
Many of the costs that we recover through pricing are shared across all users of the electricity distribution system. In many cases it is not possible nor practical to attribute costs to a specific user or group of users. In general, shared assets and shared costs are allocated proportionally across 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 in order 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 *Total 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 (transmission, operations and maintenance, administration and depreciation) with the difference being our Cost of Capital.

At all times our Target Revenue is compared with Total 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 2015 our Target Revenue is **$41.96 million**.

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

FY2015/16	Cost Category	Cost estimate $'000
	Transmission	$7,710
	Operations and maintenance	$6,221
	Administration	$4,005
	Depreciation	$8,138
	Cost of capital	$15,889
	TARGET REVENUE (revised*)	***$41,963***

** Target Revenue as determined by the Default Price Path Methodology would have resulted in a higher revenue target. EA Networks board of directors elected to keep tariff prices unchanged from the prior year, hence why we have referred here to Target Revenue (revised).*

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.

> *For example; Customers in the Irrigation customer segment do not currently contribute to our transmission interconnection costs since their electricity usage does not drive that cost. As a consequence none of that cost is attributed to that customer segment, therefore their pricing does not reflect recovery of that cost.*

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 are based on the sub-transmission capacity after removing Generation and Street Lighting capacity (as these groups do not contribute to that cost).

Interconnection Costs, which drive the majority of our Transmission Costs, are based on the demand measured on our distribution network during the 12 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. As the timings of the peaks are known (accurate to a specific 30 minute period during the year) we are able to apply the cost across the load groups that drive those peaks on our network.

We allocate Transmission Cost by applying the proportional contribution to total sub-transmission Network Capacity (kVA) less non-contributing capacity. It is notable that at present the Irrigation Customer Load Group does not incur any transmission Interconnection Charges. This is because irrigation load, despite driving significant summer-time load, does not currently contribute to any of the 12 peaks that drive Transmission Interconnect Cost.

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.

From 2015 Transmission costs now include pass-through costs, specifically; local authority rates and regulatory levies. Previously these pass-through costs were included within our Distribution prices.

Transmission Costs for 2015/16 total $7.7 million. This is comprised of;

- Connections Costs + Pass-throughs $2.6 million
- Interconnection Costs $5.1 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.

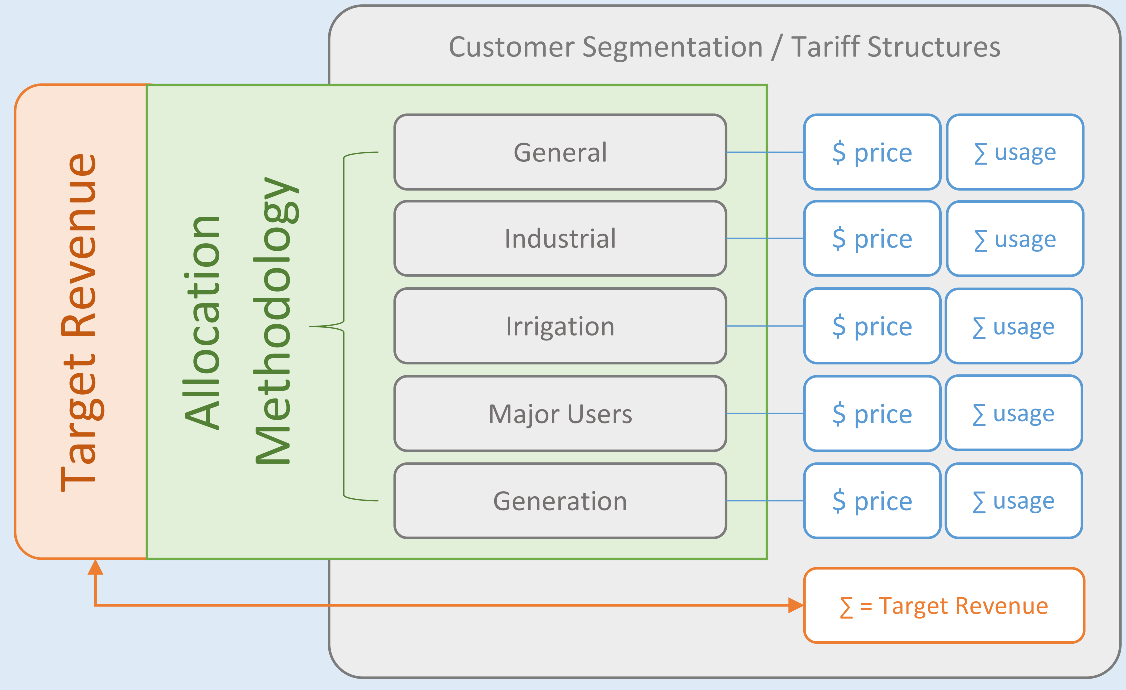
Summary of our pricing methodology

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

FY2015/16	**Cost Category**	**Cost estimate $'000**
	General	$21,122
	Industrial	$2,020
	Irrigation	$16,696
	Major Users	$1,674
	Generation	$451
	TOTAL	***$41,963***

Target Revenue by Customer Load Group is occasionally adjusted manually depending on the price change directive from our board of directors. This adjustment can be seen in the table in Appendix 1. The purpose of this adjustment is to enable the application of a standard price change across all Customer Load Groups. i.e. if we are increasing prices on average by 5%, and one Customer Load Group (based on this pricing methodology) results in a different increase, we will smooth the result across all groups. We do this to ensure price stability and mitigate volatility.

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;



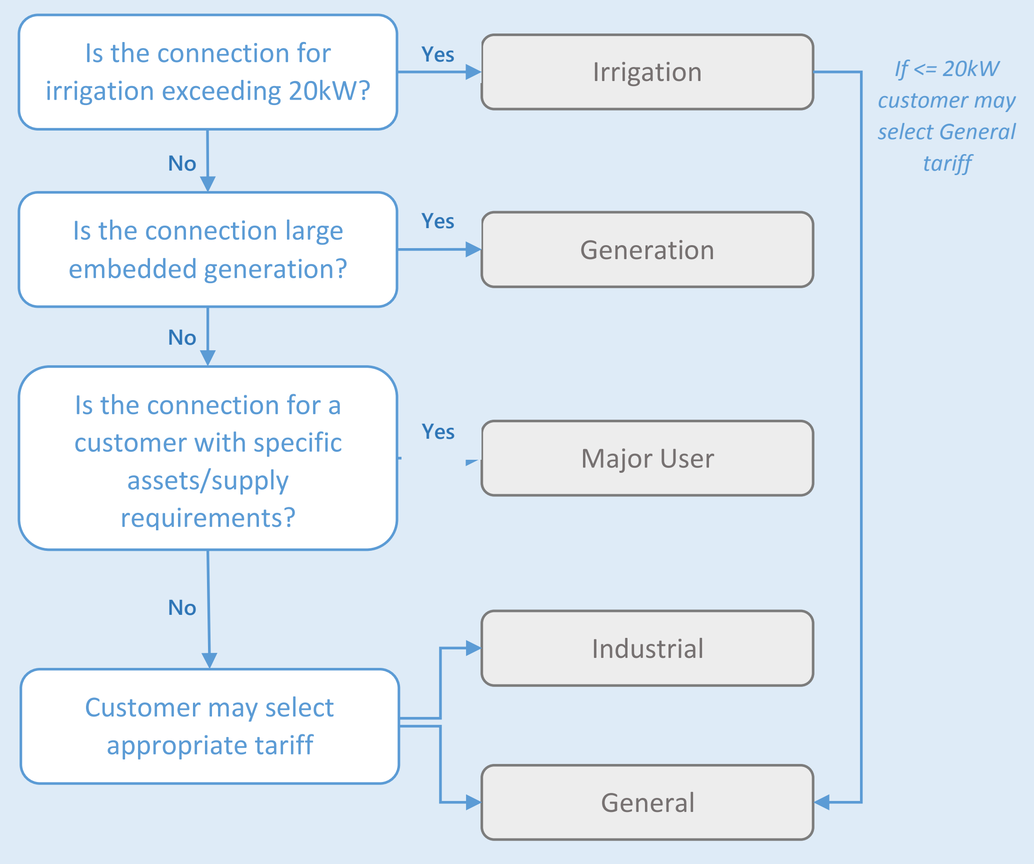
Overview of Cost Allocation Methodology

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	18,134
Segment target revenue	$21,122 million

The General Customer Load Group is for any connection made to our Low Voltage (400 volt) network including single and three phase with the exception of 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 cents/day and the quantity of electricity consumed (kWh) charged in cents/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.*

Tariff 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 26) we offer a standard tariff at $0.15 fixed rate per day fixed rate (GS20). The majority of low voltage customers are on this tariff 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 tariffs; 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. Due to the fact that we can control this load we incentivise use of this tariff 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 tariff is a legacy tariff that was established at a significant discount to the Uncontrolled Energy Tariff. To continue with stable pricing we have not altered this differential and any adjustments to prices are reflected equally between the two tariffs.

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

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 tariff. Again, by applying load profiles for each ICP we determine a rate for this tariff.

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

Tariffs available

Price Code	*Description*	*Units*
GS05	General Supply – less than 5kVA	cents/day
GS20	General Supply – 20kVA	cents/day
GS50	General Supply – 50kVA	cents/day
G100	General Supply – 100kVA	cents/day
G150	General Supply – 150kVA	cents/day
GUEN	Uncontrolled Energy	cents/kWh
GCOP	Controlled Off-Peak Energy	cents/kWh
G10N	Night Boost 10	cents/kWh
GNEN	Night only rate	cents/kWh
GEA1	EA Substation	cents/kWh
GEDG	Export kWh	cents/kWh
GUDG	Generation Credit	cents/kWh
MCRF	Floodlight – Closed	cents/fitting/day
MCRU	Under Veranda - Closed	cents/fitting/day

Industrial

Number of customers	45
Segment target revenue	$2.0 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 tariff 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 tariffs 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 tariff 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.

Tariff 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/month. 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 tariff 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.

Tariffs available

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

Irrigation

Number of customers	1,479
Segment target revenue	$16.7 million

The irrigation tariff 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.

As a consequence of this unique load and specific consumer requirements, we price our irrigation tariff 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 tariff 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.

It is notable that at this time the irrigation load group does not contribute to the costs incurred in Transpower's transmission interconnect charges. Consequently the pricing for this load group excludes any recovery of such costs. Should Transpower's interconnect charging methodology, related allocation model change or timing of the Upper South Island Peak Loads change, then the irrigation load group prices could be affected. This is beyond the control of EA Networks.

Tariff calculation

To ensure that we manage our risk we apply only a fixed rate charge to the irrigation tariff. 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 Tariff.

Based on our record of irrigation tariff 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 Tariff.

Harmonics mitigation incentive

During January 2014, we changed our connection standard with respect to Variable Speed Drives (VSD) on irrigation tariff 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 tariff 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.

More information regarding this standard can be found at www.eanetworks.co.nz/power/harmonics

Tariffs available

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

Major Users

Number of customers	5
Segment target revenue	$1.7 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.

Tariff 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 $/month, 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 also 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 cents/kWh or $/kVA/month. 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/month 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.

Tariffs available

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

Large Generation

Number of customers	3
Segment target revenue	$0.45 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 three large embedded Generators operating on our electricity distribution network; Highbank, Montalto and Cleardale. 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.

Tariff 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 customers 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.

Small distributed generation (up to 10kW)

We have made allowance for smaller distributed generators within our General load group. All small generators are offered a credit based on the Uncontrolled Energy rate where the volume applied is the minimum of Export and Import Uncontrolled Energy values (refer to tariff code GUDG within the General group). This rate includes transmission.

We presently have a small number of distributed generation connections that receive this discount.

Tariffs available

Price Code	*Description*	*Units*
LHUB	Highbank	$/month
LEHB	Highbank Energy	cents/kWh
LMHB	Highbank MD	$/kVA/month
LTHB	Highbank Interconnection RCPD Credit	$/month
LHHB	Highbank HVDC Pass-thru	$/month
LUMO	Montalto	$/month
LEMO	Montalto Energy	cents/kWh
LMMO	Montalto MD	$/kVA/month
LHMO	Montalto HVDC Pass-thru	$/kVA/month
LUCD	Cleardale	$/month
LECD	Cleardale Energy	cents/kWh
LMCD	Cleardale MD	$/kVA/month
LTCD	Cleardale Interconnection RCPD Credit	$/month
LHCD	Cleardale HVDC Pass-thru	$/month

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 tariffs. Specifically we, as a Distributor, are required to offer a fixed line charge tariff not exceeding $0.15 per day (excluding GST) to residential home users.

We provide this tariff within our General customer segment, refer to tariff 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 that would otherwise be uneconomic if revenue would be earned from standard tariffs only. Each 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 meters 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.*

Consequently we cannot disclose a table of charges or standard rates. However there is a high level of transparency of pricing made available to affected customers in a consistent manner to our general pricing methodology.

Discretionary discounts and rebates

We do not have a specific policy regarding discretionary discounts or rebates. 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 and discussion with our Shareholders Committee (a democratically elected committee representing all shareholders and customers of Electricity Ashburton Limited – trading as EA Networks).

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;

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

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

(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 exist and we take advantage of these for the long run benefit of our customers.

Where expansion is require, 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 meters 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 tariffs. Some customers simply require uncontrolled capacity regardless of time of day (e.g. irrigation). The tariff 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 tariffs 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 tariffs are designed to have regard to an end user customers demand responsiveness. This is achieved by having a range of tariffs 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 tariff that has a higher level of fixed charging will have reduced variable charging. This is critical in the tariff structure to ensure that costs are fairly recovered whilst also providing appropriate pricing signals.

Tariffs 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 tariffs 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 tariffs. These tariffs provide a significantly reduced rate compared to the uncontrolled variable rate.

We encourage the use of distributed generation by passing on to large embedded generators the Avoided Cost of Transmission (ACOT). This results in embedded generators only being charged the incremental cost of connecting to the network.

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 publically available this Pricing Methodology. In addition specific tables that detail Customer Load Groups, tariffs, 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 tariff 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 Tariff 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 tariff 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 tariff portfolio. Whilst balancing the needs of end user customers and their specific pricing requirements, our portfolio of tariffs extends to only four customer load groups and not more than sixty specific tariffs. 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 tariffs 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	
* Statistics	Number of Customers			18,134	45	1,479	1	1	1	1	5	1	1	1	19,670
	Energy	Uncontrolled		210.7	54.9	189.1	1.5	14.0	35.5	3.5	-	-	-	-	509.3
	GWh	Controlled	Off-peak	36.9	-	-	-	-	-	-	-	-	-	-	36.9
			Night	11.7	-	-	-	-	-	-	-	-	-	-	11.7
			UV/Flood lighting	-	-	-	-	-	-	-	1.6	-	-	-	1.6
			Generation	0.1	-	-	-	-	-	-	-	104.0	5.5	4.3	113.9
		Total		259.4	54.9	189.1	1.5	14.0	35.5	3.5	1.6	104.0	5.5	4.3	673.4
	Measured Demand - kVA			-	12,881	136,619	690	3,189	7,113	9,600		25,189	1,351	944	
	Load Factor			0.32	0.49	0.16	0.25	0.51	0.58	0.04		0.48	0.47	0.52	
	Sub-Transmission Transmission Capacity			91,410	12,757	136,619	690	3,189	7,113	9,600	-	25,189	1,351	944	288,861
	Netw ork Capacity			91,410	12,881	136,619	690	3,189	7,113	9,600	-	25,189	1,351	944	288,985
Allocation	$000	Transmission	Connection + pass-thrus	905	126	1,352	7	32	70	95	-	-	-	-	2,586
			Interconnection	4,067	568	-	31	142	316	-	-	-	-	-	5,123
		Subtransmission		952	133	1,423	7	33	74	100	-	-	-	-	2,722
		Zone Substations		625	87	933	5	22	-	66	-	-	-	-	1,737
		Distribution Lines		4,022	567	6,012	-	-	-	-	-	-	-	-	10,601
		Distribution Sw itchgear		1,227	173	1,834	-	-	-	-	-	-	-	-	3,234
		Distribution Substations		2,780	392	4,155	-	-	-	-	-	-	-	-	7,328
		LV Lines		2,678	-	-	-	-	-	-	-	-	-	-	2,678
		LV Street Lights		-	-	-	-	-	-	-	382	-	-	-	382
		Customer Service Connections		412	1	34	-	-	-	-	-	-	-	-	446
		Streetlight Connections		-	-	-	-	-	-	-	53	-	-	-	53
		Strategic Spares		-	-	-	-	-	-	-	-	-	-	-	-
		Other System Fixed Assets		81	11	121	1	3	6	8	-	22	1	1	256
		Dedicated	Mt Hutt	-	-	-	127	-	-	-	-	-	-	-	127
			CMP	-	-	-	-	-	234	-	-	-	-	-	234
			Highbank	-	-	-	-	-	-	-	-	378	-	-	378
			Montalto	-	-	-	-	-	-	-	-	-	46	-	46
			Cleardale	-	-	-	-	-	-	-	-	-	-	27	27
		Total		17,748	2,058	15,864	177	231	701	269	435	400	47	28	37,957
		Adminstration		3,692	9	301	0	0	0	0	1	0	0	0	4,005
		Total Revenue		21,440	2,067	16,165	177	231	701	269	436	400	47	28	41,962
Summary	$000	Transmission		4,971	694	1,352	38	173	387	95	-	-	-	-	7,710
		Operation and Maintenance		2,628	281	2,985	29	12	65	36	89	82	10	6	6,221
		Administration		3,692	9	301	0	0	0	0	1	0	0	0	4,005
		Depreciation		3,438	367	3,904	37	16	84	47	117	108	13	7	8,138
		Cost of Capital		6,711	716	7,623	73	30	165	91	228	210	25	15	15,889
		Total Revenue		21,440	2,067	16,165	177	231	701	269	436	400	47	28	41,962
		Adjustment		319	47	-530	4	-1	13	-55	179	14	14	-3	
* 2015-16 Estimated Quantities		2015 - 16 Revenue @ 2014 - 15 Rates		21,121.26	2,020.26	16,695.07	172.44	232.27	688.33	324.12	257.02	386.36	33.74	30.95	41,961.82

Appendix 2 - Pricing Schedule

Customer Group	Price Category Code	Description	Count	Code	Tariff Description	Tariff Note	Units	Previous Rates: * Disclosure purposes only: Distribution	Previous Rates: * Disclosure purposes only: Transmission	Previous Rates: Total	Rates 1st April 2015: * Disclosure purposes only: Distribution	Rates 1st April 2015: * Disclosure purposes only: Transmission plus Pass-thrus	Rates 1st April 2015: Total
General	GS05	General Supply - less than 5 kVA	42	GS05	Un-metered Supplies	Single phase less than 30A	c/day	56.46	0.00	**56.46**	56.46	0.00	**56.46**
	GS20	General Supply - 20 kVA	14,522	GS20	20 kVA	Maximum of two phase 63A or three phase 32A	c/day	15.00	0.00	**15.00**	15.00	0.00	**15.00**
	GS50	General Supply - 50 kVA	1,515	GS50	50 kVA	Three phase 33 - 63A	c/day	30.00	0.00	**30.00**	30.00	0.00	**30.00**
	G100	General Supply - 100 kVA	638	G100	100 kVA	Three phase 64 - 160A	c/day	60.00	0.00	**60.00**	60.00	0.00	**60.00**
	G150	General Supply - 150 kVA	232	G150	150 kVA	Three phase 161A or greater	c/day	90.00	0.00	**90.00**	90.00	0.00	**90.00**
				GUEN	Uncontrolled Energy		c/kWh	6.49	2.63	**9.12**	6.76	2.36	**9.12**
				GCOP	Controlled Off-Peak Energy	Controlled Load by Ripple channels 100-00 to 100-11, 103-15 to 103-17	c/kWh	1.74	0.00	**1.74**	1.74	0.00	**1.74**
				G10N	Night Boost 10	Controlled Load by Ripple channel 110-56	c/kWh	1.74	0.00	**1.74**	1.74	0.00	**1.74**
				GNEN	Night only Rate	Controlled Load by Ripple channels 110-53, 110-54, 110-55	c/kWh	0.00	0.00	**0.00**	0.00	0.00	**0.00**
				GEA1	EA Substation	25 kWh / day	c/kWh	6.49	2.63	**9.12**	6.76	2.36	**9.12**
		Embedded Generation		GEDG	Export kWh		c/kWh	0.00	0.00	**0.00**	0.00	0.00	**0.00**
		Embedded Generation		GUDG	Generation Credit	Volume is the minimum of Export and Import Uncontrolled Energy	c/kWh	-6.49	-2.63	**-9.12**	-6.76	-2.36	**-9.12**
				MCRF	Floodlight - Closed		c/fitting/day	30.72	0.00	**30.72**	30.72	0.00	**30.72**
				MCRU	Under Verandah - Closed		c/fitting/day	27.03	0.00	**27.03**	27.03	0.00	**27.03**
Irrigation	ISCH	Irrigation	1,534	ISCH	Connected kW	Value held in Chargeable Capacity	c/kW/day	31.33	2.15	**33.48**	30.77	2.71	**33.48**
				IUEN	Uncontrolled Energy		c/kWh	0.00	0.00	**0.00**	0.00	0.00	**0.00**
				ISFD	Filter installation Discount	One-off Discount payment when Filter equipment is installed	$/VSD kW	-80.00	0.00	**-80.00**	-80.00	0.00	**-80.00**
Industrial	ICMD	Industrial Supply - kVA	42	ICMD	Anytime Demand kVA		$/kVA/month	7.90	5.22	**13.12**	8.59	4.53	**13.12**
				IDEN	Day Energy		c/kWh	0.00	0.00	**0.00**	0.00	0.00	**0.00**
				INEN	Night Energy		c/kWh	0.00	0.00	**0.00**	0.00	0.00	**0.00**
				IEMD	Uncontrolled Energy		c/kWh	0.00	0.00	**0.00**	0.00	0.00	**0.00**
	ICDYMD	Industrial Day Demand	1	ICDYMD	Day Demand kVA		$/kVA/month	7.90	5.22	**13.12**	8.59	4.53	**13.12**
				ICDYAD	Anytime Demand kVA		$/kVA/month	0.00	0.00	**0.00**	0.00	0.00	**0.00**
				IEDS	Uncontrolled Energy		c/kWh	0.00	0.00	**0.00**	0.00	0.00	**0.00**
	ICDPD	Industrial Peak Demand	3	ICDPD	Peak Demand	Weekdays excluding Public Holidays	$/kVA/month	0.00	5.22	**5.22**	0.69	4.53	**5.22**
				ICDAM	Anytime Demand		$/kVA/month	7.90	0.00	**7.90**	7.90	0.00	**7.90**
				ICEN	Uncontrolled Energy		c/kWh	0.00	0.00	**0.00**	0.00	0.00	**0.00**
Large Users	LUCM	CMP	1	LUCM	CMP		$/month	20,232.16	0.00	**20,232.16**	20,232.16	0.00	**20,232.16**
				LECM	CMP Energy		c/kWh	0.00	0.00	**0.00**	0.00	0.00	**0.00**
				LMCM	CMP MD		$/kVA/month	0.00	5.22	**5.22**	0.69	4.53	**5.22**
	LUPP	Silver Fern Farms	1	LUPP	Silver Fern Farms		$/month	2,710.38	0.00	**2,710.38**	2,710.38	0.00	**2,710.38**
				LEPP	Silver Fern Farms Energy		c/kWh	0.00	0.00	**0.00**	0.00	0.00	**0.00**
				LMPP	Silver Fern Farms MD		$/kVA/month	0.00	5.22	**5.22**	0.69	4.53	**5.22**
	LUMH	Mt Hutt Ski Area	1	LUMH	Mt Hutt		$/month	10,770.17	0.00	**10,770.17**	10,770.17	0.00	**10,770.17**
				LEMH	Mt Hutt Energy		c/kWh	0.00	0.00	**0.00**	0.00	0.00	**0.00**
				LMMH	Mt Hutt MD	Weekdays excluding Public Holidays	$/kVA/month	0.00	5.22	**5.22**	0.69	4.53	**5.22**
	LUHP	Highbank Pumps	1	LUHP	Highbank Pumps		c/kW/day	7.01	2.24	**9.25**	6.54	2.71	**9.25**
				LEHP	Highbank Pumps Energy		c/kWh	0.00	0.00	**0.00**	0.00	0.00	**0.00**
				LMHP	Highbank Pumps MD		$/kVA/month	0.00	0.00	**0.00**	0.00	0.00	**0.00**
Generation	LUHB	Highbank	1	LUHB	Highbank		$/month	32,196.70	0.00	**32,196.70**	32,196.70	0.00	**32,196.70**
				LEHB	Highbank Energy		c/kWh	0.00	0.00	**0.00**	0.00	0.00	**0.00**
				LMHB	Highbank MD		$/kVA/month	0.00	0.00	**0.00**	0.00	0.00	**0.00**
				LTHB	Highbank Interconnection RCPD Credit		$/month	0.00	-78,437.09	**-78,437.09**	0.00	-122,874.45	**-122,874.45**
				LHHB	Highbank HVDC Pass-thru		$/month	0.00	4,340.99	**4,340.99**	0.00	4,524.94	**4,524.94**
	LUMO	Montalto	1	LUMO	Montalto		$/month	2,811.70	0.00	**2,811.70**	2,811.70	0.00	**2,811.70**
				LEMO	Montalto Energy		c/kWh	0.00	0.00	**0.00**	0.00	0.00	**0.00**
				LMMO	Montalto MD		$/kVA/month	0.00	0.00	**0.00**	0.00	0.00	**0.00**
				LHMO	Montalto HVDC Pass-thru		$/month	0.00	281.33	**281.33**	0.00	293.25	**293.25**
	LUCD	Cleardale	1	LUCD	Cleardale		$/month	2,579.45	0.00	**2,579.45**	2,579.45	0.00	**2,579.45**
				LECD	Cleardale Energy		c/kWh	0.00	0.00	**0.00**	0.00	0.00	**0.00**
				LMCD	Cleardale MD		$/kVA/month	0.00	0.00	**0.00**	0.00	0.00	**0.00**
				LTCD	Cleardale Interconnection RCPD Credit		$/month	0.00	-3,206.60	**-3,206.60**	0.00	-3,192.93	**-3,192.93**
				LHCD	Cleardale HVDC Pass-thru		$/month	0.00	79.27	**79.27**	0.00	82.63	**82.63**
Street Lighting	MCSL	Street Lighting		MCSL	Street lighting		c/fitting/day	23.33	0.00	**23.33**	23.33	0.00	**23.33**

All Prices are GST Exclusive

Irrigation Price category rules and notes:

1. The Irrigation category applies to any stand-alone pump (including Pivot supplies) that is a single meter installation. The Minimum chargeable Capacity is 10 kW.
2. Charges are fixed (c/kW/day) to recover costs of assets provided to deliver requred capacity.
3. 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 period of 12 months.
4. From 30 October 2013 all new Irrigation (or similar) 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.
5. The Filter installation Discount (ISFD) is a one off discount payment to eligible Irrigation connections where Harmonic Filters have been installed (or other mitigating procedure). The "VSD kW" is the cumulative kW of eligible VSD load (This value may differ from the chargeable kW of connection).

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.