

Electricity Distribution Business Pricing Methodology

Effective 1 April 2019

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Contents

1. Introduction and overview	3
2. Pricing Summary	4
3. Background	4
4. Pricing Methodology	8
5. Appendix A: Glossary.....	14
6. Appendix B: Electricity Authority Pricing Principles	15
8. Appendix C: Directors Certification	20
9. Appendix D: Regulatory Compliance Checklist	21
10. Appendix E: Prices, Customer Statistics and Target Revenue	25

1. Introduction and overview

This pricing methodology describes the approach MainPower New Zealand Limited (“MainPower”) has adopted to determine prices for consumers connected to its electricity distribution network, effective from 1 April 2019. As an electricity distribution business, MainPower is required by the Commerce Commission to publish its pricing methodology each year.

The purpose of this document is to provide customers and other interested stakeholders with relevant information on how prices have been set. This includes information on the price setting process and key inputs, assumptions, considerations, and decisions made in setting prices.

This section is a high-level explanation of how prices are set and the purpose of the pricing methodology. More detail can be found in the subsequent sections of the methodology.

When calculating prices MainPower uses the following process:

- The Company calculates the revenue required for the coming year based on budgets for all aspects of MainPower’s electricity distribution operation.
- Customers are grouped for the purposes of pricing. At present we divide customers into two regions Kaiapoi and Rangiora to reflect the historically different ownership. Within each region the Company divides customers into 7 different groups; residential, non-residential, large users, irrigation, council pumping, street lighting and temporary supply. The pricing methodology explains how MainPower allocates costs to these groups, including all the matters it must consider in setting its prices.

In 2019/20 there will be an overall increase in MainPower’s prices of 2%. This is made up of a decrease in transmission pricing component of 0.7% and an increase in the distribution pricing component of 2.8%.

MainPower is required to explain any decision to increase prices and to assess its pricing decision against criteria set by both the Electricity Authority and the Commerce Commission. These criteria are based on economic principles. The purpose of the exercise is to give customers and stakeholders some certainty that MainPower’s prices can be justified economically. This assessment is set out in the Appendices to this methodology.

The remainder of this pricing methodology is structured as follows:

- **Section 2 Pricing Summary** summarises our 2019 pricing approach
- **Section 3 Background** provides background information relevant to the development of prices. This includes a brief overview of our pricing objectives, regulatory obligations, recent consultations with customers, and our current pricing review and strategy.
- **Section 4 Pricing Methodology** sets out the methodology we have used to determine prices as at 1 April 2019, including the key considerations in determining target revenues, customer groups, pricing structures, and final charges.
- **Appendix A** contains a glossary of terms used in this document.
- **Appendix B** details the extent to which our pricing methodology is consistent with the Electricity Authority’s (“EA”) electricity distribution pricing principles.
- **Appendix C** provides Directors Certification, as required by section 2.9.1 of the IDD.
- **Appendix D** maps compliance against the Electricity Distribution Information Disclosure Determination 2012 (NZCC 22) (IDD) disclosure requirements applicable to pricing methodologies.
- **Appendix E** provides detailed information on prices, customer statistics, and target revenues (by pricing region and price type).

2. Pricing Summary

Our underlying pricing methodology is the same as that which has been applied since 1 April 2014. This is the last year we will use this 2014 methodology. A new methodology is being developed as part of the transition to more cost reflective pricing structures.

The key steps we took to set prices are:

- the current pricing methodology was confirmed for this year against our pricing objectives and strategy, amongst other considerations
- the annual target revenue requirement to be recovered through prices in 2019/20 was determined as \$58.1m. This recognises the decrease in Transpower’s transmission charges and the requirement to increase MainPower’s distribution charges in order to meet the costs of providing a safe and resilient electricity network while accommodating future development.
- The pricing structures were confirmed. These include 2 pricing regions, 7 standard customer groups, and 1 non-standard connection
- target revenue was allocated to customer groups and prices consistent with the cost allocation approach applied in the pricing methodologies since 1 April 2016.

As a consequence of an increase in MainPower’s costs and to accommodate future development MainPower has increased the distribution component of the lines price by 2.8%. The overall delivery price will increase by 2% as a result of the offsetting reduction of transmission pricing by 0.7%. Costs are allocated to customers using the same method as applied since 1 April 2016.

This process is broadly illustrated in the figure below.

Figure 1: Allocation of target revenue to pricing regions and customer groups

Target Revenue = \$58.1m													
MainPower Region \$54.0m							Non-standard \$1.6m	Kaiapoi Region \$2.5m					
Residential	Non-residential	Large	Irrigation	Lighting	Council Pumping	Temporary Supply		Residential	Non-residential	Large	Irrigation	Lighting	Council Pumping

3. Background

About MainPower

MainPower provides distribution lines services to approximately 41,000 customers throughout the North Canterbury region. A number of rural towns, including Rangiora, Kaiapoi, Oxford and Kaikoura service these rural communities. Approximately 84% of the customer base is residential, with the majority of the remaining being small commercial, farming or irrigation customers. One large connection is offered non-standard pricing in recognition of its unique cost profile.

MainPower is one of a number of consumer-owned electricity distribution businesses (“EDBs”) in New Zealand. Customers in the communities of North Canterbury own MainPower through the MainPower Trust and elect its trustees. MainPower also serves customers in the old borough of Kaiapoi who are Non-Qualifying Customers of the Company. Pricing regions are formed along the boundaries of these two areas.

Pricing and commercial objectives

The key commercial and pricing objectives that guide our pricing decisions are as follows:

- *Uniform variable pricing:* We have adopted a general objective of applying a uniform variable charge to all pricing options within a particular pricing region, irrespective of customer density, location, network configuration, or other load characteristics. There are a several exceptions to this general objective relating to pricing options that cater for specific usage and cost profiles. These exceptions are detailed below.
- *Rebates:* Rebates are paid to Redeemable Preference Shareholders (Qualifying Customers) of the MainPower Trust. Rebates are credited to Qualifying Customers' accounts on a monthly basis (although retailers may choose not to show the rebate separately on customers electricity bills). Rebate decisions do not form part of this disclosure. Qualifying Customers are advised in advance on an annual basis of the rebate levels that will apply for the coming year. The board of MainPower NZ Limited resolved to retain the rebate at the same level as 2018/19 at 2.014 cents/ kWh for the 2019/20 year.
- *Uniform pricing across the MainPower and Kaiapoi pricing regions:* The total line service charge, net of Qualifying Customer rebates applicable to customers within these pricing regions, are charged on a uniform basis. Charges after the disbursement of rebates are generally the same for customers in both MainPower and Kaiapoi pricing regions.
- *Price certainty and stability:* Our pricing structure will provide a high level of certainty and understanding, while at the same time ensuring price stability.
- *Return on investment:* Where the return on investment for MainPower is less than our Weighted Average Cost of Capital (WACC), any upward movement in charges will be calculated on the basis that the increase is applied equally across all groupings.
- *Regulatory compliance:* We will comply with all applicable regulations relating to pricing and pricing methodologies. We will also consider other regulatory guidance (i.e. the pricing principles) in our pricing decisions. In circumstances where there is a conflict between this guidance and our pricing objectives, priority is given to the pricing objectives.

Customer expectations on price and quality

MainPower has a regulatory requirement to seek input from customers as to price and quality. This helps inform pricing decisions, as well as objectives for the management of the electricity distribution network.

Summary insights from periodic customer research indicate that all customers view electricity reliability and the cost of electricity, as key performance deliverables.

MEASURE OF PERFORMANCE	IMPORTANCE RATING 2018 ²	SATISFACTION RATING 2018 ³
ALL CUSTOMERS		
Continuity - keeping the power on	96%	95%
Price - keeping costs down	97%	55%
Restoration - reducing the length of time when power is off	88%	86%
Quality - keeping flickering or dimming lights to a minimum	90%	90%
Accessibility - easy to contact my provider, if the need arises	92%	83%
Communication - keeping you informed of the electricity network	86%	79%

²Measure: Percentage of respondents rating the aspect 'important' and 'very important'.

³Measure: Percentage of respondents rating MainPower's performance as 'satisfied' and 'very satisfied'.

This suggests that we need to be mindful of cost and balancing decisions around network investment and the expectation of our customers regarding the price of electricity. There is a cost involved in investment in network maintenance and upgrades that is ultimately reflected in the price customers pay.

Regulatory requirements applicable to pricing methodologies

MainPower's distribution business is subject to regulation under Part 4 of the Commerce Act 1986 ("Part 4"), as administered by the Commerce Commission ("Commission"). Our consumer ownership means we are exempt from direct price control under Part 4. Consumer ownership and oversight provides the necessary incentives to set prices consistent with the purpose of regulation under Part 4, in the long-term interests of our customers.

We remain subject to regulatory oversight in the form of information disclosures under the Electricity Distribution Information Disclosure Determination 2012 ("IDD"), including the requirement to publish annual pricing methodologies (being this document).

MainPower is also subject to industry regulations and pricing principles, as administered by the Electricity Authority ("EA"). The EA has developed a set of principles and information disclosure guidelines to assist EDBs. Under the IDD, EDBs must disclose the extent to which their pricing methodology is consistent with these pricing principles.

The key regulatory requirements directly applicable to this pricing methodology are:

- Section 2.4.1 – 2.4.5 of the IDD regarding the disclosure of pricing methodologies
- the EA's electricity distribution pricing principles and information disclosure guidelines
- the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 (the "Low Fixed Charge Regulations")
- Schedule 6.4 of Part 6 of the Code, which sets out pricing principles for distributed generation.

This pricing methodology has been developed consistent with these requirements. Appendix B discusses the extent to which our prices are consistent with the EA's pricing principles. Appendix C provides Directors' Certification against the IDD requirements. Appendix D provides a check-list which records where in this document we have demonstrated compliance against the applicable IDD regulations.

Pricing review and strategy

MainPower is progressing a comprehensive review of our pricing methodology. The Company plans to implement more cost reflective pricing structures over future years starting in 2020. We are required by the Electricity Authority to publish a pricing roadmap every six months. This provides detail of how we intend to introduce cost reflective or service based pricing. A copy of our current pricing roadmap can be found on our website.

In 2018/19 MainPower undertook a significant piece of work to enable the identification of the costs of providing lines services to each ICP. This piece of work is key to introducing more cost reflective and service based pricing. It is our intention that more cost reflective pricing based on this analysis will be introduced from 1 April 2020.

The next step in the review is to investigate alternative pricing structures and price setting approaches to align pricing more closely with:

- **Customer preferences:** pricing structures must reflect how and when customers use electricity and recognise the choices they have in relation to energy-related appliances and products.
- **Economic and regulatory principles and industry best practice:** Our aim is to structure prices to promote more efficient use of, and investment in, the network and energy-related products and appliances. This includes consideration of regulatory and industry guidance (for example: the Electricity Authority "More Efficient Distribution Prices – What do they look like?" the Electricity Networks Association "Pricing Guidelines for Electricity Distributors" and "New Pricing Options for Electricity Distributors") on efficient pricing as well as innovative pricing approaches adopted across the sector.
- **Network cost drivers:** The model developed in 2018/19 will allow us to test different customer group scenarios, pricing options (e.g. for fixed and variable combinations, peak/off-peak pricing structures) and cost allocators. It will also assist us to analyse price shock, helping us to formulate a plan to transition any price changes over time.
- **Recent technology developments:** The deployment of smart meters across residential and small commercial connections means that electricity use can be measured at a point in time, rather than just cumulative use. Using anonymised population samples of this data, we are investigating time and/or demand based pricing structures for mass market customers which will signal the costs of providing distribution services more effectively. We currently have limited access to this customer meter data, as it is held by retailers and metering equipment providers. Access to this data in real-time looks some way off. Access to customer meter data is an issue the wider industry is currently trying to resolve. Time/demand based pricing will also provide us with the tools to accommodate evolving technologies, such as solar, batteries, electric vehicles, energy efficient appliances and home automation.

Feedback received from the public consultation undertaken between 2016-2018 will be one of the factors considered in the development of detailed pricing options and a strategy to implement any required changes.

It is likely that any option will include a greater proportion of fixed charges to reflect the largely fixed cost nature of network costs. The approach to determining the quantum of fixed charges will be assessed as part of the review of options. A greater fixed price component would also reduce MainPower's exposure to revenue volatility due to climatic conditions.

We will consult with retailers and customers on preferred new pricing options prior to making any final decisions on the pricing structure. A new pricing methodology will be issued before prices take effect. Retailers will be notified of any price changes within the notice periods specified in our conveyance only use of system agreement. Customers will be notified at least 20 business days prior to any changes taking effect.

Depending on the final outcomes of our review, we may look to introduce new pricing structures progressively across customer groups.

Some of the potential areas of change we are considering are highlighted in the figure below.

Figure 2: Potential options for restructuring pricing and impact on customers

Potential area of change	Considerations	Potential impact on customers
Change in customer groups	<p>We are reconsidering our current customer groups. We are investigating rationalisation of the current pricing groups and/or alignment of pricing structures to the Electricity Network Association's Pricing Guidelines for Electricity Distributors and those of our close peers.</p> <p>Our cost of supply model will also help us understand locational variations in the cost of supplying customers with similar usage profiles.</p>	<p>Customers may be reallocated to new pricing options and may face changes in their prices.</p> <p>Customers using less than 8,000 kWhs per annum will likely continue to receive the current 15 cents per day low fixed charge unless the Low Fixed Charge Regulations are amended or appealed. Changes to the charges paid by these customers will be dependent on the outcome of the review of the Low Fixed Charge Regulations.</p>
Aligning prices with network costs	<p>We have developed a cost of supply model that enables us to identify the costs of providing lines services at an ICP level. Output from this model will help inform which pricing structures best reflect the cost of using the network.</p>	<p>Prices will be more reflective of the costs of providing distribution services to customers. Some customers may experience a change to their prices and transition to such structures will need to be carefully managed.</p> <p>The majority of networks costs are fixed in nature therefore the balance between fixed and variable charges will shift. The method for determining levels could be based on demand, capacity or another metric.</p>
Introducing capacity, time or demand base charges	<p>The main service a distributor provides is capacity in the network to meet peak demand. This is also a key driver of network costs. In recognition of this, we are investigating the merits of introducing a network demand type charge or time of use charges which would align our pricing to the service we provide and our costs of providing that service. Smart meters have been rolled out to 66% of mass market ICPs which can (subject to</p>	<p>Customers may be charged based on the coincidence of their demand with the network's peaks, rather than or in addition to consumption. Some customers may experience a change to their prices and transition to such structures will need to be carefully managed.</p>

	data access) facilitate this form of pricing. Furthermore, we are investigating applying demand charges to larger customers given that many have time of use meters.	
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4. Pricing Methodology

MainPower has resolved that it is necessary to adjust prices on 1 April 2019. This section describes our methodology for setting prices effective from 1 April 2019. This is the same approach as has been used since the 2015/16 pricing methodology was prepared. This section provides information on our approach to:

- calculating target revenue
- determining customer groups
- allocating costs to customer groups
- setting tariffs
- pricing non-standard customer services; and
- pricing distributed generation.

Target Revenue

We determine our target revenue requirement in order that revenue collected from prices will be sufficient to cover the operating and capital costs necessary to maintain capital and/or revenue reserves at a level considered appropriate by the Board.

Figure 3 sets out our target revenue requirement for the 2019/20 pricing, relative to the 2018/19 pricing year.

Figure 3: Components of Target Revenue

	2019/20 (\$000)	2018/19 (\$000)	Change (%)
Administration and Overheads	14,986	12,809	17.0%
Operations and Maintenance	6,116	6,504	(6.0%)
Transmission charges	14,275	15,036	(5.1%)
Depreciation	13,400	13,400	0.0%
Tax	3,764	3,989	(5.6%)
Return on investment	9,981	10,619	(6.0%)
Other Revenue	(4,460)	(4,872)	(8.5%)
Target Revenue Requirement	58,062	57,485	+1.0%

At the time of setting the Target Revenue for 2019/20, forecasted consumption for the 2018/19 year was 594 GWh, which reflected variable climatic conditions (mild Winter and a wetter overall year resulting in lower demand from irrigation). Taking this into consideration and after allowing for a small increase in new connections the forecast consumption for the 2019/20 year was set at 586.4 GWh.

Administration and Overheads include costs associated with managing the day to day business activities of our distribution business, such as management, accounting, regulatory, strategy and administration costs. This also includes local body rates and Electricity Act and Commerce Act levies. The increase in the administration and overheads costs for 2019/20 reflects MainPower's continued focus on health and safety; delivering a safe, secure and reliable electricity distribution network, reorienting the business towards a customer focus, implementing intelligent

network technologies, business improvement measures; and taking a leadership role in the community. The increase in 2019/20 is largely driven by building capability of systems and people.

Operations and Maintenance captures costs associated with operating and maintaining the network, such as switching, planned and reactive maintenance and responding to faults. The reduction in 2019/20 relates largely to a change in the way we account for unbillable time.

Transmission costs are Transpower charges associated with:

- connection of MainPower's distribution network to the national grid (including interconnection, connection and new investment contract charges)
- the grid system operator function (a service which Transpower provides).

The transmission charges for MainPower have decreased to \$14,275,247 for the 2019/20 year. The decrease reflects the fact that MainPower's network peak coincided with fewer Transpower peaks across the Upper South Island during the 2018/19 measurement period.

MainPower passes the transmission costs straight through to customers, therefore the transmission component of MainPower's prices will decrease in the 2019/20 year.

Depreciation represents the return of our original capital investment and is calculated based on the net book value of our distribution business.

Tax represents budgeted tax expenditure attributed to our distribution business.

Return on Investment is driven by our 5 year view on the return on investment calculated as a WACC return on average net book value. We use a post tax WACC estimate of 6.17% for this calculation. This post tax WACC rate of 6.17% is less than the current cost of capital applied by the Commerce Commission to EDBs regulated under the Default Price-Quality Path.

Other revenue attributable to our distribution business is subtracted to determine the target revenue to recover from electricity distribution charges.

Customer groups

Our standard prices are structured across 2 pricing regions and 7 standard customer groups. We also have 1 non-standard customer which is discussed further below.

The 2 pricing regions were identified in order to provide for customers in and outside of the MainPower Trust boundaries:

- **MainPower Region (MP):** includes all customers connected to the distribution network that are not included in the Kaiapoi pricing region. These are Qualifying Customers consistent with the MainPower Trust boundary.
- **Kaiapoi Region (KE):** All customers connected to the electricity distribution network previously owned by Kaiapoi Electricity Limited, which was acquired by MainPower on 1 July 2004. These customers are non-Qualifying Customers.

Within these pricing regions, we use 7 standard customer groups:

- **Residential:** A residential customer group has been adopted in order to show compliance with the low fixed charge regulations, which apply only to domestic customers.
- **Non-residential and large users:** Non-residential and large users are treated as a separate customer group in order to:
 - o recognise the different connection load usage profiles of these customers (e.g. lower weighted average load factor), relative to residential customers
 - o facilitate our approach to complying with the low fixed charge regulations (i.e. by separating residential and non-residential customers)
- **Irrigation:** This group recognises the unique summer demand peaking load profile of these customers and incentivises efficient utilisation of available capacity in the network.
- **Lighting:** This group recognises the distinct night-time only usage profile and dedicated assets attributable to lighting connections.
- **Council Pumping:** Council pumping is a separate customer group in the MP and KE pricing region that recognises their high peak load but less frequent use.
- **Temporary supply:** This customer group recognises the need for temporary supply connections (e.g. related to construction) as well as the additional costs associated with servicing this group.

Figure 4 summarises the prices offered for each pricing region and customer group.

Key statistics for each pricing region and price option are presented in Appendix E. This includes information on:

- price components, including fixed and variable prices, by distribution and transmission components
- target revenue and allocations of target revenue to pricing regions and prices
- pricing history
- ICPs, installed kVA, customer statistics, including delivered kWh consumption and chargeable peak demand.

Figure 4: MainPower Pricing Options

Pricing Option	Customer Group	Description and rationale
Residential All Inclusive Supply	Residential	A price option offered to residential customers that allows a portion of their load (i.e. hot water heating) to be interrupted for part of the day as required for network operations. This option is priced lower than the uncontrolled price to incentivise customers to offer controllable load. This lower price recognises the benefits to all customers relating to timely management of faults and in reducing peak demand related costs. This pricing option is offered as a low user and standard user option but both are priced the same to comply with the low fixed charge regulations.
Residential Uncontrolled Supply	Residential	A pricing option targeted to residential customers that do not offer controllable load (i.e. water heating). The pricing of this option recognises the additional network costs created by not being able to interrupt supply to manage faults and peak demand. This price is offered as a low user and standard user option.
Residential Night Only	Residential	A special discounted pricing option which applies to consumption during the off-peak night period between 9.30pm to 7.30am. This incentivises customers to shift load to the off-peak night period, recognising the associated benefits in reducing peak demand. This is offered as a low user and standard user option.
Non-Residential General Supply and Large User Group	Non-residential and Large Users	This pricing option is offered to non-residential customers, typically being large users. A higher daily fixed charge is applied to take into account the lower weighted average load factor of these connections.
Irrigation	Irrigation	A pricing option targeted to irrigators in the MP pricing region. These customers are charged a fixed daily charge per kW of installed motor capacity connected. This recognises the relationship between network capacity costs and the varied size of irrigation motors connected to the network.
Lighting	Lighting	Right of way lighting and under verandah lighting are now included as optional components for other price categories. The price has been set to reflect the relatively low maintenance requirements associated with both under verandah and right of way lighting. A fixed component was added to the streetlight price in 2018. The inclusion of a fixed charge reflects the fixed nature of the costs associated with streetlighting and is consistent with ENA's guidelines.
Council Pumping	Council Pumping	A price offered in the MP and KE pricing regions for connection of Council pumping facilities. Council pumping is priced based on the uniform pricing rule.
Temporary supply	Temporary Supply	A pricing option applying to temporary connections to the network. Priced higher than standard supply, this option recognises the additional costs in

		managing temporary connections. It also appropriately incentivises customers to shift to a standard pricing option as soon as is practical.
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Allocation of Costs to Customer Groups

Allocations of costs to customer groups were last made for the 2015/16 pricing year. The cost allocation method has not changed for the 2019/20 year.

Operating costs are, wherever possible, directly attributed to customer groups that solely create the need for these costs. Remaining shared operating costs are allocated to customer groups using allocation rules based on key drivers of cost, as follows:

Figure 5: Cost allocators

	Allocation basis	Rationale
Administrative and Overhead costs	Consumption	An allocator based on connections or consumption is considered appropriate, given these costs are broadly shared by all users. We have used consumption to recognise that larger customers typically have a higher level of cost associated with them.
Operation and Maintenance costs	Net assets employed	While maintenance expenditure may arise for a variety of reasons (ie planned versus reactive maintenance), over time these costs are typically proportional to the value of assets installed. Aligning maintenance costs to net assets employed recognises this cost relationship.
Rates	Net assets employed	This recognises that rates are levied on the capital value of the network.
Levies	Consumption	This partly recognises the basis upon which these costs are charged to MainPower. For example, electricity levies are calculated based on MWhs and ICPs.
Capital Costs	Directly attributed to pricing regions using asset register records Allocated to pricing options by kWh consumption	Allocation basis seeks to represent relative utilisation of each network region.
Transmission charges	Directly attributed to pricing regions based on grid connections associated with each pricing region Allocated to pricing options by kWh consumption	Transpower charge on basis of grid connection. Consumption represents the relative utilisation of the transmission grid.

Price Setting

Prices are set to recover cost allocations to each customer group and pricing option using forecast volumes and current pricing structures. Appendix D sets out prices including the expected target revenue to be recovered from each price.

MainPower has adopted the following uniform charges that apply to most customers in each pricing region:

- The 15 cent per day low fixed charge applies to all controlled residential customers irrespective of use. This approach complies with the low fixed charge regulations.
- Variable distribution and transmission line services are charged by way of a uniform consumption charge within each pricing region. KE variable charges are set to equal MP variable charges net of rebates. This structure is adopted to set a baseline price for the majority of customers. A number of exceptions to these general pricing rules are made to recognise specific cost attributes or customer profiles as well as to encourage specific usage behaviours:
- The Residential Night Only variable price is calculated for each pricing region at approximately 80% of the Residential All Inclusive Supply variable distribution price and approximately 10% of the Residential All Inclusive Supply transmission charge. These discounted prices are set to provide an incentive for customers to shift load to the off peak night period between 9.30pm to 7.30am, thereby reducing utilisation of available service capacity during the day.
- The total variable charge for the Residential Uncontrolled Supply - Low User Option is calculated at approximately 125% of the Residential Controlled Supply total variable charge. The Residential Uncontrolled Supply fixed distribution price has also been determined at 60 cents per day. These higher prices incentivise customers to shift to the Residential All Inclusive Supply pricing option and offer controllable load.
- The fixed distribution price for Non-Residential General Supply and Large User pricing options has been determined at 50 cents per day. This takes into account the higher costs associated with connection assets for these customers and the lower weighted average load factor of this customer group.
- Revenue collected from all customer groups by way of fixed distribution charges is limited to 10% of the total fixed and variable distribution revenue. Actual percentages will vary year on year and between customer groups as a result of changes in load factor and other load characteristics.
- The variable distribution price applicable to Temporary Supply customers is maintained at approximately the same rate as the Residential Uncontrolled Supply - Low User Option variable distribution price. A fixed price of \$1.00 per day also applies. This structure recognises the additional costs MainPower faces in managing temporary supply connections and appropriately incentivises customers to shift to a standard pricing option.
- The fixed price applicable to Irrigation customers is 2 cents per day per kW of motor size connected (i.e. 50 cents per day for a motor size of 25 kilowatts) in recognition of capacity related costs.
- A fixed daily charge of 3.5 cents per fitting per day applies to Street Lighting pricing options. This reflects the fixed nature of the costs associated with street lighting infrastructure.
- The variable distribution price applicable to General Supply customers within the MP pricing region is discounted on a sliding scale basis where consumption exceeds 500,000 kWhs per annum. For consumption between 500,000 kWhs per annum and 1,000,000 kWhs a discounted price of between 8.032 cents per kWh to 1.837 cents per kWh is applied on a straight line basis. A discounted price of 1.837 cents per kWh applies for all consumption above 1,000,000 kWhs.
- The variable distribution price applicable to General Supply customers within the KE pricing region where consumption exceeds 500,000 kWhs per annum is also discounted on a sliding scale basis. For consumption between 500,000 kWhs per annum and 1,000,000 kWhs a discounted price of between 6.018 cents per kWh to 1.837 cents per kWh is applied on a straight line basis. A discounted price of 1.837 cents per kWh applies for all consumption above 1,000,000 kWhs.

Non-Standard Pricing

Only 1 non-standard customer is connected to our distribution network. The customer is situated close to a Transpower GXP and takes direct supply from the grid through MainPower's connection assets and equipment.

Prices are set for this customer to recover the actual costs we incur as follows:

- Transmission charges are passed on to the customer as billed by Transpower. Since 2015 MainPower has had customers connected to the same GXP so we allocate the Transpower charges between the non-standard customer and the remaining MainPower customers on the network based on assets at the GXP and contribution to Regional Coincident Peak demand (the measure used by Transpower for calculating

interconnection charges). Transmission charges for this non-standard customer account for 85% of lines charges, given the customer's limited usage of distribution assets.

- Distribution asset and equipment costs deployed at the connection (which have not already been recovered through capital contributions) are recovered fully through prices. This includes depreciation and a return on investment.
- Operations and maintenance costs incurred in relation to the connection are directly recovered each year in prices.
- Administration costs are recovered based on actual costs incurred.

Distribution costs are recouped through a fixed distribution charge. Transmission charges are recouped on the same basis that Transpower charges MainPower (although this is expressed on a cents per kWh basis in our pricing schedule).

Prices have been determined on this basis to discourage uneconomic bypass to the transmission grid. The fixed price seeks to minimise price volatility for both parties. Target revenues expected to be recovered from non-standard prices are detailed in Appendix D.

Our obligations and responsibilities in the event of an interruption to this customer are no different to that of other large standard customers connected to our network. The customer does have a higher level of circuit redundancy built into their connection that could result in quicker restoration times but the obligations and responsibilities to restore supply are no different. This level of redundancy is reflected in prices through the higher associated cost of the connection assets and equipment.

This one non-standard contract expires in 2020 and will be renegotiated at that time including updated pricing.

We will consider all requests for non-standard contracts on application based on the commercial merits of the proposal. Criteria by which we typically might decide to enter into a non-standard contract include:

- the customer is at risk of bypassing the network to an alternative network or energy source
- the customer has requested a non-standard connection or specialist equipment which cannot be accommodated into our standard pricing structures or capital contributions policy
- the customer requests non-standard pricing structures to mitigate risk which might otherwise impair their decision to connect to the network.

Distributed Generation Pricing

There are a limited number of small scale distributed generators connected to our network. These generation units are less than 10kW, generally under 2kW, and are typically associated with an existing ICP (i.e. photovoltaic solar panels supplementing distributed electricity supply). These connections rarely export electricity into the network.

To date MainPower has not charged for small scale distributed generation connected to the network or make payments to owners/ operators of small scale distributed generation in regards to avoided costs.

There are a small number of sites with larger scale distributed generation. Payments for avoided costs of transmission are made to one customer with large scale distributed generation under a commercial arrangement. This payment will cease in October 2019 when the amendments to part 6 of the Code take effect.

MainPower will investigate changing its policy to introduce an application charge in accordance with Part 6 of the Code. While we do not typically incur costs associated with the physical connection of small scale distributed generation, where we do, these costs will be met via contributions consistent with our capital contributions policy.

5. Appendix A: Glossary

Code	Electricity Industry Participation Code 2010
Commerce Commission (Commission)	Responsible for the regulation of EDBs as provided for under Part 4 of the Commerce Act 1986
EDB	Electricity Distribution Business
Electricity Authority (EA)	Electricity Authority
ICP	Installation Control Point: A point of connection on a local network which the distributor nominates as the point at which a retailer will be deemed to supply electricity to consumers
IDD	Electricity Distribution Information Disclosure Determination 2012, issued 1 October 2012 (Decision No. NZCC22)
kVA	Kilo Volt-Amp: Measure of apparent electrical power usage at a point in time
kW	Kilowatt: Measure of instantaneous real electrical power usage
kWh	Kilowatt hours: Measure of real electrical power usage per hour
Low fixed charge regulations	Electricity (Low Fixed Tariff Option for Domestic Consumers) Regulations 2004
Part 4	Part 4 of the Commerce Act 1986 governing the regulation of EDBs as administered by the Commerce Commission
Qualifying Customers	Redeemable Preference Shareholders in the MainPower Trust
ROI	Return on Investment
Transpower	Owner and operator of the national transmission grid
WACC	Weighted Average Cost of Capital

6. Appendix B: Electricity Authority Pricing Principles

This appendix describes the extent to which our pricing methodology is consistent with the EA’s pricing principles, pursuant to section 2.4.3(2) of the IDD.

We have reviewed our pricing methodology against the pricing principles and are of the view that our pricing methodology is broadly consistent with the principles. We also signal how alignment with the principles may be refined and improved following our pricing review.

Pricing Principle	Extent of consistency
(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;	<p>The incremental costs of connecting an additional customer to the network include the costs of connection assets specific to the customer, incremental operating and maintenance costs, and upstream reinforcement costs required to accommodate the additional connection.</p> <p>MainPower’s ‘Network Extensions and Upgrades and Capital Contributions Policy’ is the primary mechanism by which we ensure that prices recover incremental capital cost. We seek capital contributions for new connections and asset upgrades when the expected distribution revenue from a connection is less than the incremental capital costs (including a share of any upfront or future network augmentation costs). Distribution prices will therefore be in excess of incremental capital costs.</p> <p>The remaining incremental operational expenditure is recovered in distribution prices. Our fixed charge will recover a proportion of these costs regardless of the level of consumption (\$54.75 per annum in the case of all-inclusive residential, and \$182.50 per annum for non-residential). This will likely recover incremental costs for smaller connection sizes, which would usually contribute less towards operational costs. Revenue received from variable charges, which broadly increases proportional to the size of the connection and associated costs, will in most cases recover remaining incremental costs. For example, a customer on the residential all-inclusive supply price would only need to use 2,266kWh per annum to recoup the average incremental cost identified above. This also highlights that cross-subsidies may exist at very low levels of usage due to the application of the low fixed charge regulations.</p> <p>Prices are also likely to be less than stand alone cost. We understand stand alone cost to mean the cost to the customer of bypassing the network with alternative supply arrangements (e.g. connection to the grid through its own distribution assets, or alternative fuel or generation sources). For most mass market customers the costs of moving “off-grid” to a standalone energy solution (eg rooftop PV) is currently priced at a premium to distributed electricity supply. This is because the large economies of scale associated with network investments mean distribution networks currently remain competitive on price. Large customers are likely to be better placed to bypass the network at a lower overall stand alone cost. As an example, our largest connection is on a non-standard contract to discourage bypass of our network to the transmission grid. The non-standard arrangements ensure it is economic for this customer to remain connected to the network by pricing below the stand alone cost of connecting directly to the grid.</p>

	<p>We are looking to estimate stand-alone costs for different pricing regions and customer groups as part of our cost of supply modelling project. These will hopefully be provided in future pricing methodologies.</p>
<p>(ii) having regard, to the extent practicable, to the level of available service capacity; and</p>	<p>The primary service that distributors provide is access to network capacity. This pricing principle sets out that distributors should recognise this primary driver in setting prices and pricing structures.</p> <p>Signalling available service capacity in our prices is therefore important and a significant focus of our pricing review.</p> <p>We currently do not explicitly define customer groups by the level of available service capacity. However, the distinction made between low users, residential, non-residential, and large users does proxy different customer capacity profiles.</p> <p>Similarly, Residential All Inclusive and Night Special pricing options are designed to incentivise behaviours that reduce demand at the peak or during fault events. This reduces the pressure on available service capacity as well as defers investments in new capacity.</p> <p>The Irrigation price based on the installed kW capacity of irrigation motors and is designed to signal limited capacity in the high voltage distribution system. This price option, as well as capital contributions sought from irrigators, signals that upstream capacity is limited.</p> <p>One area being investigated as part of our pricing review that might improve alignment with this principle is the potential introduction of customer groups defined by load characteristics and time/demand based prices. As discussed above, we are investigating a small and large load group aligned to the typical load profiles of customers connected to our network. Peak-time/demand based charging structures could be used to signal the available service capacity on the network a different times of use.</p>
<p>(iii) signalling, to the extent practicable, the impact of additional usage on future investment costs.</p>	<p>This principle asserts that behaviour which creates additional investment costs for distributors should be recognised in pricing, and that costs should accordingly be recouped from those customers that create them. The key drivers of future network investment costs relates to new connections and system capacity growth.</p> <p>We ensure we recoup incremental connection and upstream reinforcement costs through our capital contributions policy, as discussed above.</p> <p>The use of a consumption based variable charge is another pricing approach which recognises additional usage of capacity. While prices based on kWh consumption provide a crude proxy for capacity utilisation, they send a signal that additional usage of the network creates additional costs over time.</p> <p>As part of our review, we are considering the merits of peak-time/demand pricing, particularly for the large load group. This may align pricing more closely with this principle. Large customers typically have time of use meters making it practical to charge on peak usage. By contrast, it is impractical to price the mass market other than on consumption given that real time meter data is not readily available.</p> <p>The Residential Night Only price provides incentives for customers who take up this option to shift their demand to the off-peak night period. The Residential All Inclusive price signal provides incentives to customers that offer up</p>

	<p>interruptible load which can be used to manage faults and reduce peak demand. In combination, these options appropriately signal the impact of additional usage on investment costs.</p> <p>As discussed above, the Irrigation price signals capacity constraints on the 11kV network attributable to this fast growing customer group by levying a higher fixed daily charge on relatively larger irrigation motors.</p>
<p>(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 customers' demand responsiveness, to the extent practicable.</p>	<p>This principle sets out the economic principle of "Ramsey Pricing". This principle asserts it is economically efficient to charge more to those customers that have a higher willingness to pay and less to those with a lower willingness to pay.</p> <p>As a practical example, this principle suggests that a business that must operate or face significant shutdown costs would pay relatively more than a customer who is willing to have their supply interrupted. This is considered economically efficient as those customers that demand a service the most, pay the most. In competitive markets, customers that pay more will typically demand a higher level of service.</p> <p>In practice, it is difficult to apply willingness to pay considerations explicitly given the difficulty in measuring customer demand responsiveness. However, evidence from previous customer surveys suggests, in general that there is a low willingness to pay for higher value services for the majority of customers.</p> <p>We consider the willingness to pay principle can be practically applied by allowing customers to self-select into pricing options that balance their willingness to pay with the quality of supply they receive. For instance, the Residential Uncontrolled pricing option is higher recognising that customers who do not want their hot-water load interrupted are willing to pay more for that supply. Similarly, the Residential Night Only price is targeted at customers who are willing to limit their demand at the peak in preference for a lower off peak charge. Our non-standard pricing also partially recognises willingness to pay considerations by customers that are readily able to bypass the network.</p>
<p>(c) Provided that prices satisfy (a) above, prices should be responsive to the requirements and circumstances of stakeholders in order to:</p>	<p>This suggests Principle A takes priority over these considerations.</p>
<p>(i) discourage uneconomic bypass;</p>	<p>This allows for a discount on price or other incentives being offered to customers at risk of bypassing our network. As discussed above, bypass options are likely to be more applicable to larger customers that have options over where they locate their business or which have access to alternative energy supply (e.g. gas, generation, the transmission grid).</p> <p>We have one customer that is directly supplied from Transpower's national grid, using MainPower's equipment. This customer could readily bypass the distribution network in favour of a direct connection to the grid. To recognise this risk, we have entered into a non-standard contract with this customer and prices are set with reference to the actual (or incremental cost) of offering these services. This discourages uneconomic bypass to the transmission grid.</p>

<p>(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</p>	<p>This principle allows for negotiation over price in recognition of different levels of service (e.g. redundancy) or non-standard arrangements (greater fixed charge component to reduce risk).</p> <p>As discussed above, MainPower has one non-standard contract and is willing to negotiate on price and quality outcomes and non-standard arrangements with other customers where necessary. In addition to incremental cost pricing, a flat fixed charge is applied which reduces price variability for this customer.</p> <p>Price and quality trade-offs are also sometimes addressed as part of our capital contributions policy. For instance, if a customer requires specialist equipment or connection redundancy then a contribution is typically sought from the customer to recover costs associated with this investment.</p>
<p>(iii) where network economics warrant, and to the extent practicable, encourage investment in transmission and distribution alternatives (eg distributed generation or demand response) and technology innovation.</p>	<p>This principle seeks to encourage the development of distributed generation, load control, and technological innovation.</p> <p>We do not levy annual charges on the connection of small scale distributed generation to the network. This provides appropriate incentives for customers to invest in distributed generation as they do not face any additional distribution costs beyond that related to their standard ICP connection. Furthermore, distributed generation will usually lower a customer's variable distribution charge resulting in lower annual charges. This further provides incentives to invest in this technology.</p> <p>Where there are upfront costs in relation to connecting distributed generation, which is unlikely, this will be dealt with as part of our capital contributions policy.</p> <p>Currently there are 8 customers with large scale distributed generation connected to our network (ie greater than 10kW), and we are considering our own generation investments at Mt Cass. We pay avoided transmission payments to one of these connections by commercial negotiation.</p> <p>Demand response measures are encouraged through the use of our Residential All Inclusive and Residential Night Only pricing options, which are priced attractively to incentivise customers to offer up interruptible load or reduce their demand at the day time peak, respectively.</p>
<p>(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.</p>	<p>This principle requires distributors to consider the impact of pricing structure changes on customers (e.g. to be cognisant of price shock).</p> <p>MainPower has embarked on stage one of a consultation strategy to determine the needs and preferences of our customers whose feedback will be one of the factors considered in the development of any new prices.</p> <p>As part of our current review of pricing, we are also considering progressively transitioning customers to new pricing structures over time to avoid price shock.</p> <p>The principle also requires the development of prices to be transparent. We consider that the information provided in this pricing methodology provides appropriate explanations of how we have set prices and the rationale for doing so.</p>
<p>(e) Development of prices should have regard to the impact of transaction costs on retailers,</p>	<p>This principle was added by the Electricity Authority out of concern that some distribution pricing structures were overly complex, creating transaction costs for retailers and customers. It also sought to minimise the potential for prices</p>

<p>customers and other stakeholders and should be economically equivalent across retailers.</p>	<p>to be structured in a way which might favour certain retailers over others, the objective of this being to enhance retail competition on distribution networks.</p> <p>MainPower has a conveyance form of contractual relationship with our customers. We bill customers through our contractual arrangements with the retailer, but retailers are not charged directly. This reduces transaction costs for retailers as retailers do not need to rebundle distribution charges to align with their own pricing.</p> <p>Our current prices are not overly complex, align with industry standard pricing, and do not favour one retailer over another. We are also investigating further alignment to the ENA price standardisation guidelines as part of our review.</p>
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8. Appendix C: Directors Certification



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CERTIFICATE FOR YEAR-BEGINNING DISCLOSURE Pursuant to Clause 2.9.1 of Section 2.9

We, ANTHONY CHARLES KING and STEPHEN PAUL LEWIS, being Directors of MainPower New Zealand Limited, certify that, having made all reasonable enquiry; to the best of our knowledge:

- a) The following attached information of MainPower New Zealand Limited prepared for the purposes of clause 2.4.1 of the Electricity Information Disclosure Determination 2012 in all material respects complies with that determination; and
- 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.



Anthony Charles King

21.3.2019

Date



Stephen Paul Lewis

21.3.2019

Date

www.mainpower.co.nz

9. Appendix D: Regulatory Compliance Checklist

IDD Clause	Disclosure Requirement	Pricing Methodology Reference
2.4.1	Every EDB must publicly disclose, before the start of each disclosure year, a pricing methodology which-	This Pricing Methodology will be published on our website prior to 1 April 2019.
2.4.1(1)	Describes the methodology, in accordance with clause 2.4.3 below, used to calculate the prices payable or to be payable;	See below for document references to compliance against clause 2.4.3.
2.4.1(2)	Describes any changes in prices and target revenues;	<p>Prices will increase by 2% for 2019/20 and we have described the reasons for this in section 4. There has been no change to the cost allocation method – this has been carried forward in current prices.</p> <p>Changes in target revenues are described in Section 4 under the heading ‘Target Revenue’ and in Figure 3. The component costs of target revenue have changed to reflect revised budgets.</p>
2.4.1(3)	Explains, in accordance with clause 2.4.5 below, the approach taken with respect to pricing in non-standard contracts and distributed generation (if any);	See below for document references to compliance against clause 2.4.5.
2.4.1(4)	Explains whether, and if so how, the EDB has sought the views of customers, including their expectations in terms of price and quality, and reflected those views in calculating the prices payable or to be payable. If the EDB has not sought the views of customers, the reasons for not doing so must be disclosed.	The details of our previous consultation with customers on their price and quality expectations is discussed in section 3 under the heading ‘Customer expectations on price and quality’.
2.4.2	Any change in the pricing methodology or adoption of a different pricing methodology, must be publicly disclosed at least 20 working days before prices determined in accordance with the change or the different pricing methodology take effect.	Not applicable. We have not changed our pricing methodology. This document has been updated from our previous pricing methodology documents incorporating changes to reflect updates to target revenue, and other metrics etc.
2.4.3	Every disclosure under clause 2.4.1 above must-	
2.4.3(1)	Include sufficient information and commentary to enable interested persons to understand how prices were set for each customer group, including the assumptions and statistics used to determine prices for each customer group;	<p>We consider this document provides information on how prices have been set.</p> <p>A glossary is provided in Appendix A of terms commonly used in this document. Section 3 provides relevant context to our pricing decisions and signals potential outcomes of our current pricing review. Section 4 sets out the key inputs, assumptions, considerations and decisions made in respect of our pricing, consistent with the IDD disclosure requirements. Appendix B details the extent to which our pricing methodology is consistent</p>

		with the EA's pricing principles. Appendix D summarises where in the document we have shown compliance with the pricing regulations. Appendix E details final prices, customer statistics and target revenue information.
2.4.3(2)	Demonstrate the extent to which the pricing methodology is consistent with the pricing principles and explain the reasons for any inconsistency between the pricing methodology and the pricing principles;	See Appendix B. We consider that our pricing is consistent with the pricing principles. We also discuss how potential changes to our pricing, signalled as part of our pricing review, may align more closely with these principles.
2.4.3(3)	State the target revenue expected to be collected for the disclosure year to which the pricing methodology applies;	See Section 4, Figure 3 and Appendix E. Figure 3 compares this year's target revenue to our previous year's target revenue by cost component. Appendix E details the breakdown of target revenue by price and cost component.
2.4.3(4)	Where applicable, identify the key components of target revenue required to cover the costs and return on investment associated with the EDB's provision of electricity lines services. Disclosure must include the numerical value of each of the components;	See section 4 under the heading 'Target Revenue'. Figure 3 and Appendix E provides numerical values for each cost component.
2.4.3(5)	State the customer groups for whom prices have been set, and describe- the rationale for grouping customers in this way; the method and the criteria used by the EDB to allocate customers to each of the customer groups;	See Section 4 under the heading 'Customer Groups'.
2.4.3(6)	If prices have changed from prices disclosed for the immediately preceding disclosure year, explain the reasons for changes, and quantify the difference in respect of each of those reasons;	Overall prices will increase by 2% for 2019/20 and we have described the reasons for this in section 4
2.4.3(7)	Where applicable, describe the method used by the EDB to allocate the target revenue among customer groups, including the numerical values of the target revenue allocated to each customer group, and the rationale for allocating it in this way;	See Section 4 under the heading 'Allocation of Costs to Customer Groups'. Costs are directly attributed to customer groups and prices where possible. Shared costs are allocated using appropriate cost allocators reflective of key network drivers. This approach has been carried forward from our 2016 pricing methodology. Appendix E provides the numerical values of target revenue allocated to each customer group.
2.4.3(8)	State the proportion of target revenue (if applicable) that is collected through each price component as publicly disclosed under clause 2.4.18.	Appendix E details the proportion of target revenue to be collected from each customer group consistent with how prices are published in our pricing schedules.
2.4.4	Every disclosure under clause 2.4.1 above must, if the EDB has a pricing strategy-	

2.4.4(1)	Explain the pricing strategy for the next 5 disclosure years (or as close to 5 years as the pricing strategy allows), including the current disclosure year for which prices are set;	Our pricing strategy is discussed in section 4, under the heading 'Pricing Review and Pricing Strategy'. This strategy is subject to the outcomes of our review.
2.4.4(2)	Explain how and why prices for each customer group are expected to change as a result of the pricing strategy;	<p>See Section 3, Figure 2 under the heading 'Pricing Review and Pricing Strategy'. We are unable to describe how prices will change as a result of applying our pricing strategy as the details of our pricing review have yet to be finalised.</p> <p>We plan to consult extensively with customers, retailers, and other affected parties to gain feedback on any proposed changes this year. As part of this, we will provide information on how different customer groups will be affected.</p>
2.4.4(3)	If the pricing strategy has changed from the preceding disclosure year, identify the changes and explain the reasons for the changes.	See Section 3, under the heading 'Pricing Review and Pricing Strategy'. This pricing strategy is largely unchanged from last year. However, our review is evolving as it progresses which means we have reprioritised project work streams.
2.4.5	Every disclosure under clause 2.4.1 above must-	
2.4.5(1)(a) and (b)	<p>Describe the approach to setting prices for non-standard contracts, including-</p> <p>the extent of non-standard contract use, including the number of ICPs represented by non-standard contracts and the value of target revenue expected to be collected from customers subject to non-standard contracts;</p> <p>how the EDB determines whether to use a non-standard contract, including any criteria used;</p> <p>any specific criteria or methodology used for determining prices for customers subject to non-standard contracts and the extent to which these criteria or that methodology are consistent with the pricing principles;</p>	<p>See Section 4, under the heading 'Non-Standard Pricing'.</p> <p>We seek to recover actual costs incurred from our only non-standard customer, reflective of the incremental costs of the assets and costs to operate and maintain the connection.</p> <p>See Appendix B for a discussion of the extent to which our non-standard pricing aligns with the pricing principles. Prices are greater than incremental costs associated with the customer and are priced to discourage bypass to the transmission grid.</p>
2.4.5(2)	<p>Describe the EDB's obligations and responsibilities (if any) to customers subject to non-standard contracts in the event that the supply of electricity lines services to the customer is interrupted. This description must explain-</p> <p>the extent of the differences in the relevant terms between standard contracts and non-standard contracts;</p> <p>any implications of this approach for determining prices for customers subject to non-standard contracts;</p>	<p>See Section 4, under the heading 'Non-Standard Pricing'.</p> <p>Our obligations and responsibilities in the event of an interruption to supply are no different to that of any other standard large user. However, our sole non-standard customer does have a higher level of circuit redundancy which might result in quicker restoration times. This is reflected in charges through the higher value of assets associated with these circuits.</p>

2.4.5(3)	Describe the EDB's approach to developing prices for electricity distribution services provided to customers that own distributed generation, including any payments made by the EDB to the owner of any distributed generation, and including the- (a) prices; and (b) value, structure and rationale for any payments to the owner of the distributed generation.	See Section 4, under the heading 'Distributed Generation Pricing'. We do not currently charge for distributed generation connections. Physical connection costs are usually immaterial and are dealt with under our normal capital contributions policy. We are currently reviewing whether to introduce a charge in line with the part 6 of the Code. We make avoided transmission payments to the largest distributed generation connection in accordance with that customer's connection agreement. This payment will cease in October 2019 when amendments to Part 6 of the Code take effect.
2.9.1	Where an EDB is required to publicly disclose any information under clause 2.4.1, clause 2.6.1 and sub clauses 2.6.3(4) and 2.6.5(3), the EDB must at that time publicly disclose a certificate in the form set out in Schedule 17 in respect of that information, duly signed by 2 directors of the EDB.	See Appendix C for Directors Certification

10. Appendix E: Prices, Customer Statistics and Target Revenue

MainPower New Zealand Limited											Appendix E																											
1 April 2019 Disclosure of Lines Services Pricing and Pricing Methodology as required under Part 4 of the Commerce Act 1986.											Line Service Charges and Revenue Exclude GST and Prompt Payment Discounts, Other Discounts and Customer Rebates																											
Customer Groupings and Categories		Line Services Charging Schedule at 1 April 2019						Pricing History at 31 March 2019				Customer Statistics 2019-2020				Revenue Requirement 2019-2020				Line Business Operating Costs (Targeted Revenue) 2019-2020				Return (Targeted)		Return (Maximum)												
MainPower Region ICPs - MP Consumer Group	Code	Distribution		Transmission		Total		Date Introduced		Previous Charge		Customer Numbers	Installed Capacity	kWhs Delivered	Chargeable Demand	Distribution		Trans Variable	Total Lines	Other Revenue*	Total Revenue	Trans Costs	Operational Expenditure		Depreciation	Taxation*	Total Costs	Surplus After Tax	Return on Assets	Return at WACC	WACC							
		Code	cents/day	Code	c/kWh	Code	c/kWh	Code	c/kWh	Date	Date					cents/day	c/kWh						Fixed	Variable								Admin & O/Hs	Ops & Mctc					
Net Equity 2019-2020: \$253.00m																																						
General Supply																																						
General Supply Fixed Charge	MPAISTD	FXD	15.00	MPAISTD	-24S1	8.032	MPAISTD	-24S5	2.471	MPAISTD	-24S9	10.503	01-Sep-01	01-Apr-15	15.0	8.508	18,144		173,531,281																			
Residential All Inclusive Supply	MPALLU	FXD	15.00	MPALLU	-24S1	8.032	MPALLU	-24S5	2.471	MPALLU	-24S9	10.503	01-Oct-04	01-Apr-15	15.0	8.508	9,153		50,024,503																			
Residential Uncontrolled Supply Low User Option	MPUCSTD	FXD	60.00	MPUCSTD	-24S1	8.032	MPUCSTD	-24S5	2.471	MPUCSTD	-24S9	10.503	01-Sep-01	01-Apr-15	60.0	8.508	1,496		10,607,423																			
Non Residential - General supply	MPNONRES	FXD	50.00	MPNONRES	-24S1	8.032	MPNONRES	-24S5	2.471	MPNONRES	-24S9	10.503	01-Sep-01	01-Apr-15	50.0	8.508	5,864		115,735,995																			
Irrigation kW Connected Charge (47,500 kW)	MPIRR	FXD	2.00	MPIRR	-24S1	8.032	MPIRR	-24S5	2.471	MPIRR	-24S9	10.503	01-Sep-01	01-Apr-15	2.0	8.508	1,457		77,390,490																			
Council Pumping	MPCOUNPUMP	FXD	15.00	MPCOUNPUMP	-24S1	8.032	MPCOUNPUMP	-24S5	2.471	MPCOUNPUMP	-24S9	10.503	01-Sep-01	01-Apr-15	15.0	8.508	161		9,431,976																			
Total General Supply																	36,295		436,721,658																			
Other Supply																																						
Residential Night Only (All Inclusive)	MPNISTD	FXD	30.00	MPNISTD	NG1	4.124	MPNISTD	NG9	0.247	MPNISTD	NG9	4.371	01-Oct-04	01-Apr-15	15.00	2.368	1,648		2,977,670																			
Residential Night Only - Low User (All Inclusive Low User)	MPNLU	FXD	15.00	MPNLU	NG1	4.637	MPNLU	NG9	2.471	MPNLU	NG9	7.108	01-Sep-01	01-Apr-15	0.00	5.106	752		644,425																			
Residential Uncontrolled Supply Low User Option	MPUCLU	FXD	15.00	MPUCLU	-24S1	10.085	MPUCLU	-24S5	2.471	MPUCLU	-24S9	12.556	01-Sep-01	01-Apr-15	15.00	10.561	509		2,459,224																			
Street Lighting	MPSTLGT	FXD	3.50	MPSTLGT	-24S1	4.492	MPSTLGT	-24S5	2.471	MPSTLGT	-24S9	6.963	01-Sep-01	01-Apr-15	3.50	4.968	114		2,647,531																			
Large User Group	MPLGEUSER	FXD	50.00	MPLGEUSER	-24S1	5.153	MPLGEUSER	-24S5	2.471	MPLGEUSER	-24S9	7.624	01-Sep-01	01-Apr-15	50.00	6.374	31		35,169,288																			
Large User Group No Fixed Charge	MPLGEUSERNF	FXD	0.00	MPLGEUSERNF	-24S1	5.153	MPLGEUSERNF	-24S5	2.471	MPLGEUSERNF	-24S9	7.624	01-Sep-01	01-Apr-15		6.374	8		11,297,633																			
Right of Way Lighting (Now optional component codes)	ROW1			ROW1		4.492	ROW1		2.471	ROW1		6.963				4.968																						
Under Verandah Lighting (Now optional component codes)	UV1			UV1		4.492	UV1		2.471	UV1		6.963				4.968																						
Temporary Supply	MPTEMP	FXD	100.00	MPTEMP	-24S1	10.465	MPTEMP	-24S5	2.471	MPTEMP	-24S9	12.936	01-Feb-10	01-Apr-15	100.00	12.955	377		199,285																			
Total MainPower Region Consumer Group																	39,734		492,116,717																			
MainPower ICPs - Direct Supply																																						
Net Equity 2019-2020: \$2.09m																																						
Total Direct Supply Consumer Group	140	FXD	60.625	140	1	0.000	140	5	2.099	140	9	2.099	01-Sep-01	01-Apr-14			1	12	65,516,943	7,298																		
Total Direct Supply Consumer Group																																						
Kaipoi Region ICPs - KE Consumer Group																																						
Net Equity 2019-2020: \$6.28m																																						
General Supply																																						
General Supply Fixed Charge	KEAISTD	FXD	15.00	KEAISTD	-24S1	6.018	KEAISTD	-24S5	2.471	KEAISTD	-24S9	8.489	01-Nov-05	01-Apr-15	15.00	8.508	820		8,098,143																			
Residential All Inclusive Supply	KEALLU	FXD	15.00	KEALLU	-24S1	6.018	KEALLU	-24S5	2.471	KEALLU	-24S9	8.489	01-Nov-05	01-Apr-15	15.00	8.508	696		3,548,521																			
Residential Uncontrolled Supply Low User Option	KEUCSTD	FXD	60.00	KEUCSTD	-24S1	6.018	KEUCSTD	-24S5	2.471	KEUCSTD	-24S9	8.489	01-Nov-05	01-Apr-15	60.00	8.508	10		53,717																			
Non Residential - General supply	KENONRES	FXD	50.00	KENONRES	-24S1	6.018	KENONRES	-24S5	2.471	KENONRES	-24S9	8.489	01-Nov-05	01-Apr-15	50.00	8.508	233		6,405,837																			
Council Pumping	KECOUNPUMP	FXD	15.00	KECOUNPUMP	-24S1	6.018	KECOUNPUMP	-24S5	2.471	KECOUNPUMP	-24S9	8.489	01-Nov-05	01-Apr-15	15.00	8.508	19		740,436																			
Street Lighting	KESTLGT	FXD	3.50	KESTLGT	-24S1	2.478	KESTLGT	-24S5	2.471	KESTLGT	-24S9	4.949	01-Nov-05	01-Apr-15	3.50	4.968	2		251,426																			
Large User Group	KELGEUSER	FXD	50.00	KELGEUSER	-24S1	4.606	KELGEUSER	-24S5	2.471	KELGEUSER	-24S9	7.077	01-Nov-05	01-Apr-15	50.00	7.092	7		9,483,302																			
Total General Supply																	1,787		28,581,381																			
Other Supply																																						
Residential Night Only (All Inclusive KEAISTD)	KENISTD	FXD	30.00	KENISTD	NG1	2.110	KENISTD	NG5	0.247	KENISTD	NG9	2.357	01-Nov-05	01-Apr-15	15.00	2.368	107		144,022																			
Residential Night Only - (All Inclusive Low User)	KENILU	FXD	15.00	KENILU	NG1	2.623	KENILU	NG5	2.471	KENILU	NG9	5.094	01-Nov-05	01-Apr-15	0.00	5.106	67		38,594																			
Residential Uncontrolled Supply Low User Option	KEUCLU	FXD	15.00	KEUCLU	-24S1	8.071	KEUCLU	-24S5	2.471	KEUCLU	-24S9	10.542	01-Nov-05	01-Apr-15	15.00	10.561	6		27,022																			
Right of Way Lighting (Now optional component codes)	ROW1			ROW1		2.478	ROW1		2.471	ROW1		4.949				4.968																						
Under Verandah Lighting (Now optional component codes)	UV1			UV1		2.478	UV1		2.471	UV1		4.949				4.968																						
Temporary Supply	KETEMP	FXD	100.00	KETEMP	-24S1	10.465	KETEMP	-24S5	2.471	KETEMP	-24S9	12.936	01-Feb-10	01-Apr-15	100.00	12.955	4		-																			
Total Kaipoi Region Consumer Group																	1,971		28,791,020																			
Net Equity 2019-2020: \$261.36m																																						
Total all Consumer Groups																	41,706		586,424,680																			