Pricing Methodology: 1 April 2017

Executive Summary

The Lines Company Limited (TLC) provides electricity lines services to customers on its network. TLC undertakes to provide reliable service to an identified point of connection at an agreed capacity. Both the reliability of service and the revenues recovered are subject to threshold and disclosure requirements determined by the Commerce Commission.

The Commerce Commission does not specify how the revenue should be recovered. The prices set for individual customers or groups of customers are determined by the network in accordance with its stated pricing methodology. The Pricing Methodology 2017 is a disclosure required by the Commerce Commission. It explains, for the benefit of interested stakeholders, why and how TLC determines the prices payable by its customers.

For the period 1 April 2017 to 31 March 2018, TLC's target revenue is $42.7 million. This figure represents the cost of providing electricity lines services to approximately 24,000 installations and allows for a return on investment to shareholders. At 31 March 2017, the estimated investment in the network is $180 million.

To ensure the efficient use of network assets in a manner that provides service quality benefits to the customer at an affordable price and a regulated return to the shareholder, TLC charges customers for their capacity and demand requirements as opposed to their energy consumption.

TLC contracts with and invoices customers directly. This relationship means that TLC and customers have an existing communication channel by which to discuss the balance between price and service quality.

In order to maintain network reliability at a level that customers want, the capital expenditure on the network must match the rate of depreciation. If additional growth is required, whether to provide extra reliability, capacity or connections the capital needed to fund this growth must be met by additional revenue.

The pricing methodology used to allocate costs and set prices will determine how accurately charges paid by each customer recover the cost of service to their installation. The current pricing methodology of demand charging means that prices should recover at least the marginal cost of service to an individual and no more than the standalone cost of service.

The first step in setting prices is to determine the annual revenue requirement of the Network. Groups of customers are then identified based on region, demand density and supply voltage. Where individual capacity requirements are significant TLC will negotiate directly with the customer. Shared Network costs are allocated across the customer groups leading to clear differentials based on the network cost drivers of asset value and demand density. Finally, a pricing model is developed. Currently, this model is a combination of capacity and demand charges, supported where evidenced, by dedicated asset charges.

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Abbreviations

TLC	The Lines Company
EDB	Electricity Distribution Business
EA	Electricity Authority
ComCom	Commerce Commission
AMP	Asset Management Plan
ICP	Installation Control Point
kW	Kilowatt
kWh	Kilowatt-hour
kVA	Kilovolt-ampere
ACOT	Avoided Cost of Transmission
LNI	Lower North Island Transpower transmission region
RCPD	Regional Coincident Peak Demand
DPP	Default Price Quality Path
ID2012	Information Disclosure Determination 2012
IM2012	Input Methodologies Determination 2012
POS	Point of Supply

Pricing Abbreviations

Consumer Group Terminology

HT	Hangatiki	**WK**	Whakamaru	**OK**	Ohakune
ON	Ongarue	**NP**	National Park	**TK**	Tokaanu
LV	Low Voltage Supply (400V)			**HV**	High Voltage Supply (11kV/33kV)
HI	High Density (demand density ≥ 50kVA/km)				
LO	Low Density (demand density < 50kVA/km)				

Pricing Plans

LFCP	Low Fixed Charge: Regulated distribution tariff
SUP	Standard User: Capacity normally < 100kVA
MUP	Major User: Capacity normally ≥ 100kVA

1. Pricing Methodology Overview

In order to accurately reflect the cost of service, TLC delivery charges are payable according to the capacity each consumer requires and the assets used to provide that capacity. The methodology used to set the prices for the delivery charges is based on assessed or measurable quantities of power rather than energy usage. Demand charging and dedicated asset charges enable TLC to set prices that signal to the consumer the relative costs of safe, reliable supply to their installation. Sequentially, there are four stages employed in setting prices:

1. Determine target revenue within regulated levels;
2. Identification of customer groups;
3. Allocation of target revenue between these groups;
4. Development of delivery charges to recover target revenue and send pricing signals aligned to consumer behaviour.

Figure 1: Sequential diagram of TLC's Pricing Methodology

Crucial to this process is alignment to the regulatory models developed by the Commerce Commission and Electricity Authority. These models ensure that revenue and prices reflect the cost of operating an efficient distribution network.

1.1. Customer Consultation

Customer engagement is an essential process in the development of a quality product or service. Consumers connected to TLC's network have a direct contractual relationship with TLC for the supply of capacity at a known price and level of quality. This relationship provides a level of transparency in pricing not common across the industry where lines charges are bundled with retail energy prices.

Supporting this direct customer relationship is a dedicated customer team, including a fault and outage response team. Amongst other things, in conjunction with network engineers, TLC employees are available to provide energy and demand management advice. Six times a year, customers receive a customer newsletter outlining company news and network issues. Performance targets and current indicators of service expectations are presented in the Asset Management Plan[1] and Annual Report[2].

Newsletters, website updates and regulatory disclosures are effective at communicating matters of a routine nature. Regular community clinics are also run and these provide consumers with the opportunity to discuss with TLC representatives their opinions and expectations regarding price and the level of service. Customer viewpoints are considered during the development of investment decisions in all aspects of TLC's service delivery.

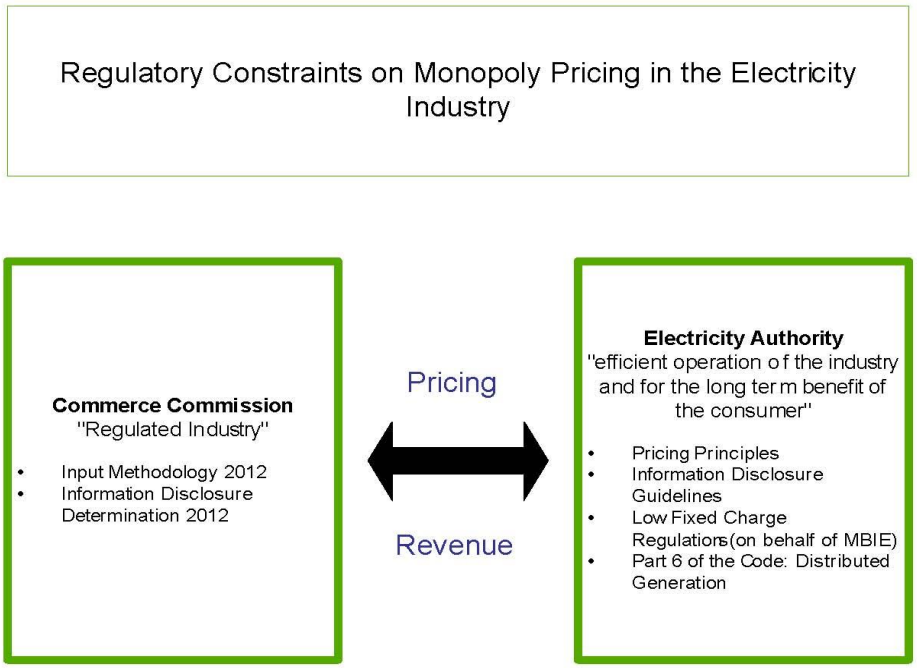
[1] 2016 TLC Asset Management Plan and 2017 TLC Asset Management Plan Update
[2] 2016 TLC Annual Report

Two independent reviews were initiated in 2016. The Electricity Authority initiated a review of TLC's pricing and related load control practices, the incentives they place on consumers, and the outcomes they influence. As part of the review process, the Authority ran an online questionnaire to gather customer feedback on their experiences with TLC's pricing and load control practices. To date, this review has not been released.

The second review was initiated by TLC Board. This independent review has included consultation and interviews with customers. The terms of reference for this review and the consultant's reports are available on TLC's website. Further discussion of this review is presented in the section on Strategy.

1.2. Regulatory Considerations

The EDB model is not subject to competitive market forces. As a natural monopoly, the model is subject to both quality of service and price regulation. The following diagram looks only at the pricing constraints that TLC is subject to under current regulations.



1.2.1. Commerce Commission

TLC is one of 29 companies operating in New Zealand that provide electricity lines services. Sixteen of these companies, including TLC, are obliged to set target revenue and service levels according to Input Methodology requirements determined by the Commerce Commission (ComCom). TLC is subject to the "Default Price/Quality Path" (DPP) requirements, and compliance is tested annually on revenues charged and network reliability performance against regulatory set targets. The Input Methodology is used to establish the capital requirements of an efficient distribution business and the service level appropriate.

Public disclosure under the Information Disclosure Determination 2012 (ID2012) is one method of verifying TLC compliance with the DPP. This document (Pricing Methodology) and other regulatory disclosures to ComCom can be viewed and downloaded from TLC's website. The scope and framework

of the Pricing Methodology is prescribed by Section 2.4: Information Disclosure Determination 2012 (ID2012).

Refer to Appendix 3: Information Disclosure Determination 2012 Alignment Table.

1.2.2. Electricity Authority

The statutory objective set for the Electricity Authority (EA) by the Electricity Industry Act 2010 is:

To promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

The primary tools used by EA to assist in the delivery of this objective are:

1.2.2.1. Pricing Principles

EA have elected to use a principles-based model rather than a prescriptive one-size fits all.

Refer to: Appendix 1: Pricing Principles Alignment Table.

1.2.2.2. Information Disclosure Guidelines

These guidelines have been developed to aid distributors in the disclosure of their pricing methodologies and to specifically show alignment with the pricing principles model.

Refer to: Appendix 2: Information Disclosure Guidelines Alignment Table.

1.2.2.3. Low Fixed Charge Regulations

The Low Fixed Charge Regulations 2004 (LFC) are monitored by the Ministry of Innovation and Employment (MBIE). The EA is charged with administering compliance. Under the LFC, TLC is obliged to offer a regulated tariff to its domestic consumers. This tariff must:

- Have a fixed charge of not more than 15 cents per day (excl. GST and net of prompt payment discount);
- The average domestic consumer should pay no more in total per year on the regulated tariff than on any alternative plan.

The structure of the LFC regulations results in a significant portion of domestic consumers paying less than the incremental cost of supply to their installations. As total revenue is constrained by regulation, it is implicit that lost revenue is sought elsewhere, effectively creating a level of cross subsidy. This position is recognised in Section (a) (i) of the Pricing Principles, "…except where subsidies arise from compliance with legislation and/or other regulation."

1.2.2.4. Distributed Generation

Regulation on the structure and value of both payments to generators and prices charged is contained within Part 6: Connection of Distributed Generation of the Electricity Industry Participation Code 2010.

The presence of generators on the TLC distribution network presents a set of technical connection issues. These issues range from safety considerations to system interference with neighbouring connections. Most large distributed generators have dedicated assets and associated charges plus load and associated charges when generation is not occurring, or injection is at a level lower than the load required.

1.3. Changes to Pricing Methodology

There are no major changes to The Lines Company pricing methodology from previous years.

1.4. Pricing Strategy

TLC is committed to a programme of network renewal and development which provides customers with an acceptable price/quality trade-off and also is economically right sized to ensure the network is not over capitalised and shareholder value not compromised. An adequate revenue stream is required to build and maintain the network in accordance with the set strategy and prices must be periodically adjusted to earn the required revenues. The company has elected to price at below sustainable regulatory levels in response to the difficult economic times faced by both individual customers and communities.

From 1 April 2017, TLC believes it must increase its prices to continue the path of revenue recovery to sustainable levels. This higher price path will likely result in price increases to customers at rates higher than inflation over the next three years culminating with revenues being aligned to regulatory targets by 2019. Price increases in the range of 3% - 5% (including recoverable transmission costs) are currently being forecast but remain dependent on inflation staying at currently low levels and inflation only adjusted increases in transmission charges. The additional revenue will be used to secure network renewals, address ever changing hazard management requirements and deliver improved returns to our community trust shareholder.

The advanced meter rollout project and how customers respond to demand side management opportunities is expected to have an impact on the forward price path. Consistent with TLC's pricing methodology, long-term pricing benefits to the customer are clearly available if load is shifted.

Service-Based Pricing Review

In September 2016 TLC announced an independent review of the current pricing methodology. After ten years of the current methodology being applied, it was believed that substantive review was warranted to provide a plan for future pricing decisions.

The board issued Terms of Reference that have shaped this review with the objective to understand how a pricing methodology can be applied to achieve optimum equity, simplicity and transparency for the customers on TLC's network.

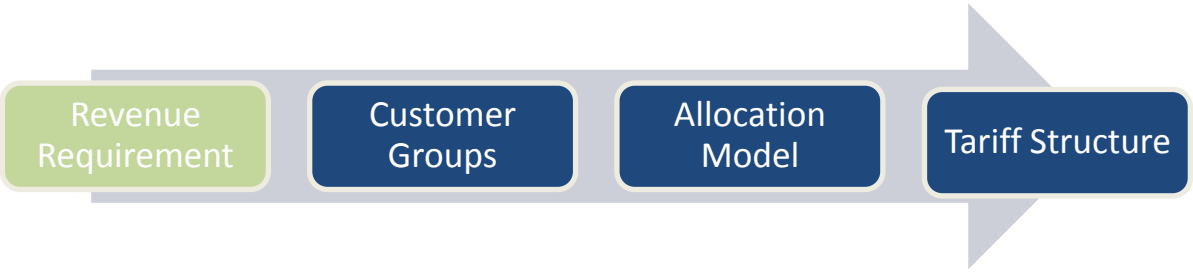
This review has been conducted by independent consultants, Roger Sutton and Lynne Taylor of PwC. Their reports were released during March 2017. The reports recommend moving from the current pricing approach to a volumetric time of use based pricing methodology.

TLC is now considering the potential for change, including attention to unintended consequences including technical competency of metering and billing systems, and ensuring any system is acceptable to customers. At the time of publishing, no final decision on change has been made.

Full copies of the terms of reference along with the reports from the consultants and statement from TLC board are available at the company website: http://thelinescompany.co.nz/news/pricing-review.

2. Standard Contract Pricing Methodology

2.1. Revenue Requirement



Sequential diagram of TLC's Pricing Methodology

Target revenue is based on the aggregate of the following costs:

- Return on capital invested;
- Return of capital invested (depreciation);
- Recovery of direct operating costs (e.g. maintenance, etc.);
- Recovery of customer and administration costs (e.g. billing, etc.);
- Recovery of Pass-through costs (e.g. industry rates and levies);
- Recoverable costs (e.g. Transpower and ACOT).

The Input Methodologies 2012 (IM2012) developed by ComCom provides the methods and processes necessary to establish revenue targets. Price setting is the mechanism by which the network investment and related costs to operate a network are recovered. The investment in the network by TLC includes assets such as poles, wires, transformers, switchgear and substations. Valuation of the asset investment for price-setting purposes is estimated at $180 million. The value of the assets owned by an EDB is commonly referred to as the Regulated Asset Base (RAB).

IM2012 identifies distribution, customer and administration costs that are either allowable, as in the asset renewal programmes necessary to maintain a quality provision of supply, able to be passed on, as in industry levies and rates, or recoverable, as in Transmission and ACOT.

Aggregation of these costs provides an indicative Total Target Revenue for the pricing period starting 1 April 2017. These costs are quantified in the following table (Table 1).

Target Revenue: 1 April 2017 - 31 March 2018 Projected Distribution, Pass-through and Recoverable Costs			
Cost	Description	$m	%
Distribution	Capital related	$ 25.4	57%
	Maintenance	$ 5.8	13%
	Customer and administration	$ 5.6	13%
Pass-through	Rates and levies	$ 0.5	1%
Recoverable	Transmission	$ 7.4	17%
Total to Recover		$ 44.7	100%
Total Target Revenue		$ 42.7	96%

Table 1: 2017 Total Target revenue

Total Target Revenue of $42.7m is the combined revenue from both standard contracts $36.5m and non - standard contracts $6.2m.

2.1.1. Distribution Costs

Distribution costs account for an estimated 83% of total costs.

ComCom regulates electricity distribution monopolies using a price/quality trade-off. Provision of reliable supply, measured regarding outage duration and frequency, is balanced against the asset investment to deliver customer capacity requirements. Higher capital costs suggest higher revenue which suggests higher prices. Implicit is the assumption that asset investment should result in increased standards of reliability. Customer consultation is very important and these consultations should provide customers with the opportunity to influence the investment decisions being made on their behalf.

Underlying these costs are requirements around safety and quality. For example, TLC must keep the voltage plus other more technical quantities such as harmonics levels within certain limits.

The cost lines in Table 1 detail:

1. A return on capital invested, combined with a return of capital invested, at the Commerce Commission regulated rate, accounts for 57% of total costs recovered through revenues. These costs include:
    a. Depreciation of assets at regulated rates;
    b. Return on investment at a regulated rate.

    The current target revenue provides a return less than that regulated by the Commerce Commission.

2. Operating expenditure is 26% of total costs and include:
    a. Network Maintenance – vegetation management, lines and pole maintenance fall within this cost line;
    b. Customer and Administration – all other costs required to support and run an EDB including network management, business support systems and customer engagement.

2.1.2. Pass-through Costs

Annual levies to the Electricity Authority and Utilities Disputes Ltd are identified in Comcom's input methodology as expenses that may be passed through to customers of TLC[3]. Also included in this category of costs are local council and authority rates that are charged on fixed assets used for subsystem delivery. These costs represent 1% of total costs.

[3] S3.1.2(3) Input Methodology 2010

2.1.3. Recoverable Costs

Transmission and ACOT charges represent 17% of total costs. Table 2 provides a breakdown of these costs by Point of Supply (POS).

Recoverable Costs - Transmission and ACOT	
Point of Supply	2017 $m
Hangatiki	$ 3.8
Whakamaru	$ 0.2
Ohakune	$ 0.6
Ongarue	$ 1.3
National Park	$ 0.7
Tokaanu	$ 0.8
Total	$ 7.4

Table 2: 2017 Recoverable Costs

Recoverable costs include transmission costs payable to Transpower for connection assets and interconnection demand charges, plus avoided cost of transmission payments (ACOT) made to generators feeding directly into TLC distribution network during half hour periods of Regional Coincident Peak Demand (RCPD).
Transpower charges are a combination of connection and interconnection charges. The interconnection charge is a variable charge relating specifically to a grid supply point, and the quantity (kW) is the average of the loads at that POS co-incidental with the top 100 half hour peaks (RCPD) experienced on the Lower North Island transmission grid (LNI) over the 12 months ended 31 August.

The Whakamaru supply point is unique, and transmission charges are replaced by a different mechanism. Recoverable costs for the Whakamaru supply point are based on economic transmission costs avoided.

ACOT payments to embedded generators on the network are legislated at the same rate as the interconnection charge from Transpower.

During the 12 months ended 31 August 2016, TLC controlled load to avoid possible LNI peaks, with the intention of minimising transmission charges, hence minimising the costs recovered from customers.

2.1.3.1. Interconnection Rates

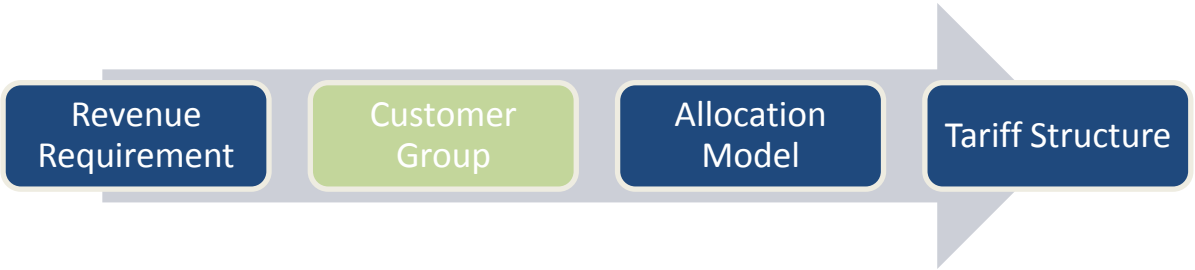
Since 2008, the interconnection rate has increased from $63.74 to $123.98 per kW, approximately 95%. During this same period, Transpower's interconnection charge to TLC has increased from $2.55m to $4.31m or 69%. The difference in increases between the rate and the charge is indicative of the reduction in TLC's Regional Coincident Peak Demand (RCPD). TLC's load controlling policy and practices have contributed to the reduction in RCPD and interconnection charges that TLC recovers from our customers.

2.1.3.2. Changes to Recoverable Costs

In July 2016, a Te Awamutu – Hangatiki 110kV line was commissioned. The commissioning resulted in a different application of the Transmission Pricing Methodology by Transpower at Hangatiki (and other Grid Exit Points not directly affecting TLC).

In summary, the Hangatiki GXP changed to an interconnection link and connection charges at Hangatiki reduced. Transpower issued a credit note to TLC in March 2017 of $0.26m which has been applied to Hangatiki Recoverable Costs effective April 2017.

2.2. Customer Group



Sequential diagram of TLC's Pricing Methodology

To recover Target Revenue, TLC must identify the customers from whom this revenue will be procured. Cost drivers are identified and customers are grouped according to their exposure to these drivers and individual influence on these drivers.

The nature of a distribution network means that there is a high level of fixed cost to be shared. Where possible, customers who benefit from the dedicated use of distribution assets are charged accordingly.

Defining a Customer Group and the key features considered is discussed below.

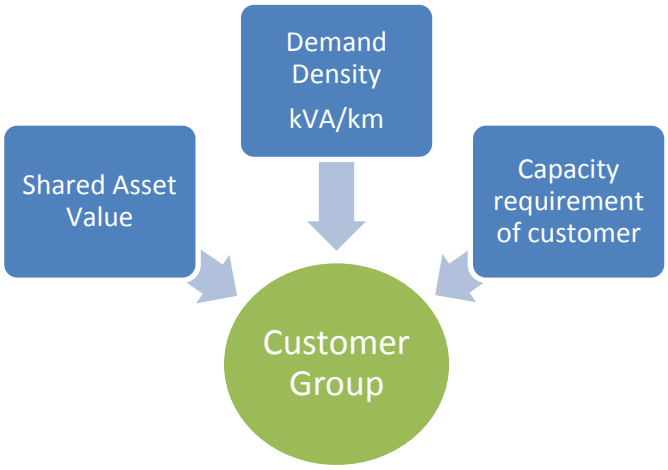


Figure 2: Customer Group Definers

Shared Asset Value

Distribution assets are aggregated at a regional level, aligned to transmission POS and include the length of line, transformers, poles and other distribution related assets. By grouping customers based on POS, TLC is able to best match invested infrastructure costs to those who benefit. An exception is when the capacity requirements of a customer are sufficiently large to require investment in additional dedicated network infrastructure. Individual customer contracts are negotiated with these customers. There are six different pricing regions: Hangatiki, Whakamaru, Ohakune, Ongarue, National Park and Tokaanu. Where an area could be supplied from more than one POS, the customers in that area are grouped with those with whom they share the most in common.

Five of these regions correspond to POS on the national grid. These five POS are where the distribution network, as owned and maintained by TLC, intersects with the national transmission network (National Grid) operated by Transpower. The sixth POS is Whakamaru where TLC minimises transmission costs by contracting directly with a generator.

Demand Density

Demand density at an ICP is an important cost driver. Demand density is a ratio of demand (capacity as measured at the distribution transformer) to line length from the feeder. When compared with high demand density, low demand density, generally illustrated in remote areas with a low population count, requires an increased level of investment per connection. Customers are grouped according to demand density at the point of connection.

Capacity Requirement

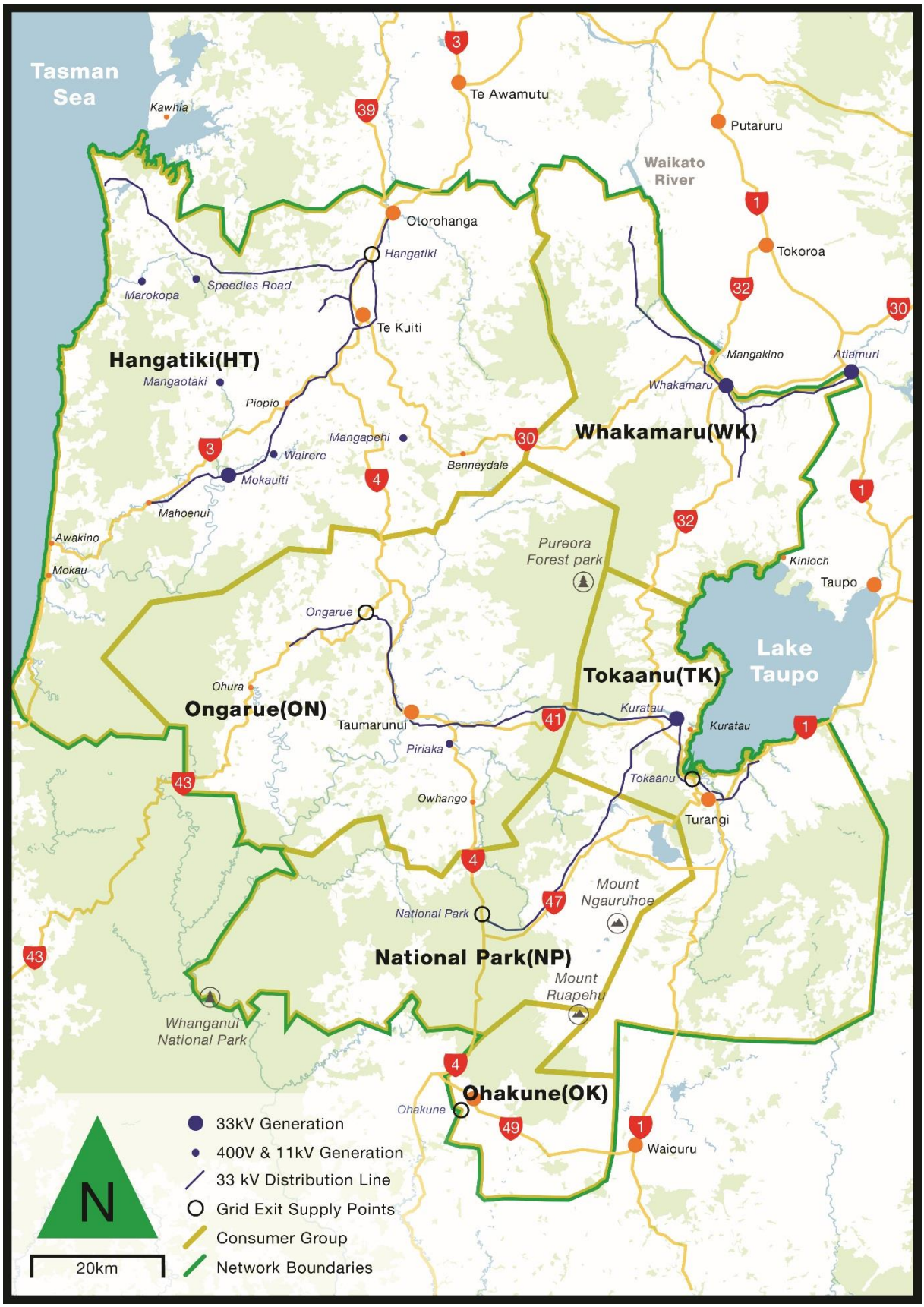
The capacity requirement of individual customers is also considered. If sufficiently large, the capacity requirement of an individual customer can affect the reliability and supply of capacity to other customers on the local network.

The following table provides an illustration of the Standard Contract Consumer Group matrix and a count of customers within each defined group.

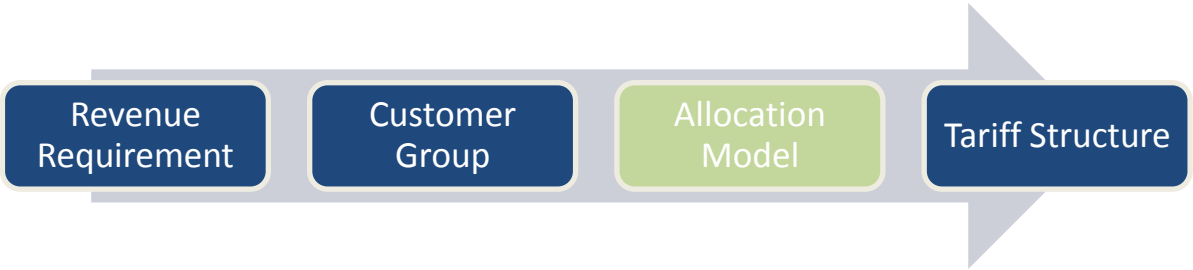
Consumer Groups (Excluding Non Standard Contracts) 2017 Total Customer Number - 23,615								
	Hangatiki				Whakamaru			
	HVHI	HVLO	LVHI	LVLO	HVHI	HVLO	LVHI	LVLO
Capacity <100kVA	1,407	1,661	4,790	1,086	85	1,175	803	400
Capacity ≥100kVA*	19				1			
	Ohakune				Ongarue			
	HVHI	HVLO	LVHI	LVLO	HVHI	HVLO	LVHI	LVLO
Capacity <100kVA	216	0	1,759	0	480	766	2,786	596
Capacity ≥100kVA*	0				1			
	National Park				Tokaanu			
	HVHI	HVLO	LVHI	LVLO	HVHI	HVLO	LVHI	LVLO
Capacity <100kVA	72	153	388	190	131	103	4,496	43
Capacity ≥100kVA*	2				6			
HV=High Voltage; LV=Low Voltage; HI=High Density; LO=Low Density *As Priced on MUP								

Table 3: Standard Contract Customer Groups and 2017 ICP count

TLC Network and Regional Consumer Groups



2.3. Allocation Model



Sequential diagram of TLC's Pricing Methodology

Having quantified Target Revenue and defined Customer Groups, allocation of costs between Customer Groups and/or individual customers is required.

The measurements and statistics relevant to the allocation of costs incurred are provided in the following table. Cost information is in reference to total network costs as provided in Table 1 and thus includes costs for all customers, not just Standard Contract customers.

2017 Allocation Assumptions and Costs					
Supply Point	Demand Density	No. of connections	Line Length	Network	kW Load
		ICP #s	km	kVA 000's	kW/kVA 000's
Hangatiki	High	6,222	797	67.5	51.0
	Low	2,747	907	18.0	7.2
Whakamaru	High	891	203	7.1	3.4
	Low	1,575	508	18.3	7.9
Ohakune	High	1,977	201	15.5	9.3
	Low	-	-	-	-
Ongarue	High	3,269	451	24.1	10.5
	Low	1,362	599	8.2	3.0
National Park	High	463	113	5.4	4.7
	Low	343	194	5.6	1.7
Tokaanu	High	4,634	307	32.3	12.2
	Low	146	89	0.9	0.3
Network		23,629	4,369	202.9	111.2

Table 4: 2017 Allocation Model Assumptions and Costs. Part 1

2017 Allocation Assumptions and Costs				
Supply Point	RAB	Capital Related Costs	Maintenance Costs	Customer & Admin Costs
	$m	$m	$m	$m
Hangatiki	$ 71.2	$ 10.1	$ 2.3	$ 2.4
Whakamaru	$ 29.2	$ 3.8	$ 0.8	$ 0.5
Ohakune	$ 16.1	$ 2.2	$ 0.2	$ 0.4
Ongarue	$ 28.3	$ 4.3	$ 1.5	$ 1.0
National Park	$ 13.9	$ 1.8	$ 0.3	$ 0.2
Tokaanu	$ 20.9	$ 3.2	$ 0.7	$ 1.1
Network	$ 179.6	$ 25.4	$ 5.8	$ 5.6

Table 5: 2017 Allocation Model Assumptions and Costs. Part 2

Regulatory Asset Base (RAB)

- This provides the base for allocation of capital-related costs.

Capital related costs

- These costs are based on the estimated value of the network assets as retrieved from asset management systems. The costs include an allowance for both a return *on* capital and a return *of* capital at the regulated rate of return. If dedicated network asset use can be identified, the cost will be allocated to those customers receiving the benefit.

Operational costs

Maintenance Costs

- Asset management systems are used to identify costs by customer group, where available. Supply voltage, demand density and network age impact total maintenance costs.
- Maintenance costs include both direct and indirect costs (being principally network support costs) and are allocated between high and low voltage supply. Historical averages are used to give a cost per km of line. These costs are allocated to customer groups based on line length statistics. If there are negotiated contracts in place, a cost is deducted from the customer group allocation.

Customer and Administration

- Administration costs include the provision of shared services including corporate governance, finance, human resources, pricing and regulatory management and information technology. Unless clearly attributable to an individual these costs are allocated across the customer groups with reference to capital costs. If clearly attributable, the cost will be passed on as a service fee or as part of a negotiated contract.

- Customer costs include billing services, demand side management services and customer support services. The costs are allocated to customer groups on a proportional basis (ICP count) or as part of a negotiated contract.

Pass-through costs

- These are allocated in the same manner as outlined for Recoverable costs.

Note: In previous years these costs were allocated by ICP. These costs represent less than 1% of revenue, and the adjustment is not seen as a major change to the methodology.

Recoverable costs

- Recoverable transmission costs are allocated differently depending on a customers' pricing plan:
  - For SUP and LFCP, variable kW Load at the point of supply;
  - For MUP, a combination of the Connection Charge and Individual Peak Demand or Connection charge and Coincidental Demand quantities.

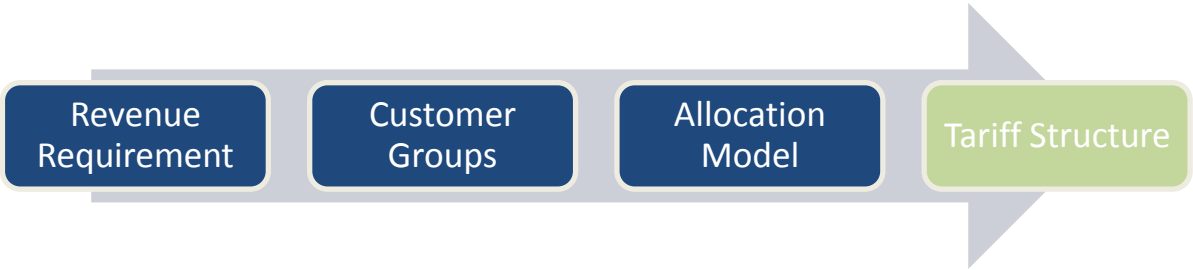
Target Revenue by Customer Group

The following table shows target revenue allocation by Standard Contract customer groups. This allocation has been made in line with the methodology and assumptions outlined above but excludes revenue earned from Non-Standard Contract and Distributed Generator customers.

Consumer Groups (Excluding Non Standard Contacts) 2017 Total Target Revenue - $36.5m ($m)								
	Hangatiki				Whakamaru			
	HVHI	HVLO	LVHI	LVLO	HVHI	HVLO	LVHI	LVLO
Capacity <100kVA	$ 3.11	$ 2.68	$ 6.11	$ 1.20	$ 0.23	$ 3.27	$ 0.72	$ 0.61
Capacity ≥100kVA*	$ 1.87				$ 0.38			
	Ohakune				Ongarue			
	HVHI	HVLO	LVHI	LVLO	HVHI	HVLO	LVHI	LVLO
Capacity <100kVA	$ 0.35	$ -	$ 2.20	$ -	$ 0.79	$ 1.14	$ 3.85	$ 0.67
Capacity ≥100kVA*	$ -				$ 0.15			
	National Park				Tokaanu			
	HVHI	HVLO	LVHI	LVLO	HVHI	HVLO	LVHI	LVLO
Capacity <100kVA	$ 0.15	$ 0.32	$ 0.65	$ 0.81	$ 0.40	$ 0.15	$ 4.09	$ 0.04
Capacity ≥100kVA*	$ 0.34				$ 0.23			
HV=High Voltage; LV=Low Voltage; HI=High Density; LO=Low Density *As Priced on MUP								

Table 6: 2017 Target Revenue Allocations by Customer Group

2.4. Tariff Structure



Sequential diagram of TLC's Pricing Methodology

The recovery of Target Revenue requires the development of a methodology to set prices. Currently, the majority of EDBs use a methodology that combines volumetric (energy consumption), demand charging for their larger capacity customers and daily fixed charges. Before 2007, TLC used a similar mixed charging methodology. In 2007, TLC moved to a charging methodology aligned to economic costs of service provision.

Meters capable of recording energy use over pre-set time periods are referred to as Time-of Use (TOU) meters. The limited number of TOU meters at customer installations in 2007 was an issue for consideration by TLC when moving to demand charging. However, the network constraints presented by an aged network with low demand and connection density, combined with a high proportion of customers with low annual consumption, and alternatives such as solar reducing in price meant that a volumetric charging methodology was unsustainable. In 2007, TLC adopted demand charging for all of its customers.

In addition to the fixed and variable demand charges, TLC has dedicated asset charges. Dedicated asset charges apply when there is a clear and identifiable benefit provided to customers.

The three main pricing components used to recover distribution related target revenue at TLC are:

- Fixed charge (Network Charge);
- Variable charge (kW Load Charge);
- Dedicated asset recovery (Transformer and other dedicated assets including relay fees).

Complementing these pricing components are:

- Low Fixed Charge: this charge forms part of the regulated distributor tariff option, as required, for eligible customers. The charge must be no greater than 15 cents per day, and when combined with a variable charge, must be such that the average consumer will pay no more than on any alternative tariff. For eligible consumers, this charge replaces the network charge;
- Service fees: these fees recover costs incurred in the provision of dedicated services such as de-energisation and re-energisation requests;
- Transmission charges: these charges include the recovery of recoverable and pass-through costs.
- Relief Policies and rebates: These offer relief at times when a change to individual circumstances mean that current charging is inappropriate. The financial impact of these policies has a small overall impact on total revenue recovery.

  The policies can be found on the company website:
  www.thelinescompany.co.nz/customers/customer-relief-policies.

2.4.1. Demand Charging

TLC's demand charging methodology uses a fixed charge to represent the maximum capacity requirement of the installation and a variable charge to provide consumers with a signal of their demand during periods of load control.

The allocation of revenue between these two pricing components is decided with reference to the short and long-term strategic goals of the business. Pricing differentials are used to influence customer behaviour and elicit a demand side response (DSM). TLC derives nearly 50% of Target Revenue from variable charges. From a consumer viewpoint, if the largest part of their monthly bill is a charge that they can reduce by load management, then the consumer is in a position to make a cost/benefit decision.

Determination of capacity and demand quantities is influenced by the type of meter at the installation. As at 31 October 2016, approximately 74% of the installations on TLC network had electronic meters.

For the purpose of data collection and kW load development, where an electronic meter is installed:

- Insufficient qualifying load control periods will result in the relevant Profiled kW load being applied; [4]
- Insufficient or inadequate interval data will result in the relevant Profiled kW load being applied.

To learn more about the processes and rules used to calculate billable quantities to consumers for both Network Charge and kW Load, plus the transitional options used to ensure pricing equity between consumers with different meter types, please follow the links provided in the customer section of the website www.thelinescompany.co.nz/customers/pricing-and-billing or request a hard copy of the 2017 Pricing Policy.

Fixed charge

The quantity used in the fixed charge is a reflection of the maximum capacity requirement of the connection. This capacity requirement is established as part of the connection agreement at the time of connection and unless there is a significant change to the structure or use of the connection, it is expected that the capacity requirement will remain constant from year to year. This charge is referred to as the **Network Charge**, and most connected customers incur this charge.

Variable charge

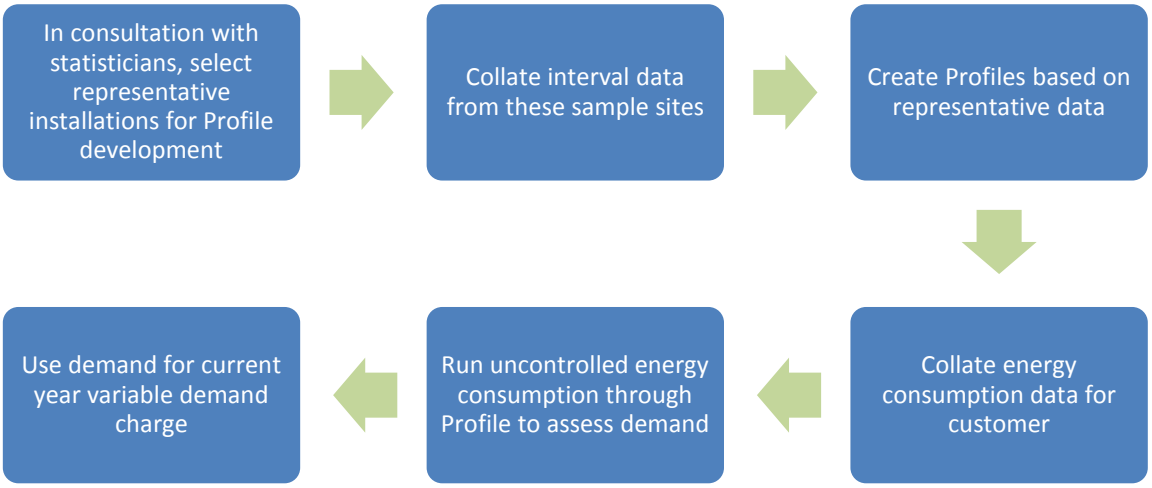
To determine the uncontrolled load at an ICP with an electronic meter, TLC uses the average of six two-hour periods recorded during periods of load control. This charge is referred to as **"kW Load"**, and is usually reset on an annual basis. The charge applies to customers on the Standard User Pricing Plan and Low Fixed Charge Pricing Plan.

Electronic meters can record consumption in time intervals. In 2007, TLC used a representative selection of electronic meters and their uncontrolled interval data to mathematically produce an equation predicting that a certain level of uncontrolled energy consumption has a point of equivalence with kW Load ('profile'). Statisticians are used by TLC in the development of the profile equations.

[4] A discussion and anticipation of insufficient data was introduced in the Pricing Methodology 2012.

Using kW Load profiles, TLC was able to introduce variable demand charging even though the vast majority of its customers still had volumetric meters.

The following diagram shows the essential steps in this process. The process level decision and rules are provided on both the company website[5] and in hard copy on request.



As at 31 October 2016, 74% (49% in the prior year) of consumers benefited from the installation of electronic meters. TLC has acted to ensure charging equity between customers with different meters by offering an opt-back process to the consumer's relevant profile.

TLC is currently installing advanced electronic meters at all connections on the network. This project is prioritised and it is expected that within 1-2 years substantially all connections will have electronic meters. The availability of the opt-back process is a transitional measure and only available to the individual installation for two years following the installing of an electronic meter.

Of the approximate 17,000 electronic meters, as at 1 April 2017, approximately 31% of consumers are utilising the opt back process to the relevant profile.

Customers on the Major Users Plan (MUP) do not have a kW load charge. The singular impact of these consumers on local network infrastructure and demand peaks means the capital investment incurred is irrespective of time of use, and recovery of this cost is through the use of dedicated asset and/or capacity charges.

2.4.2. Dedicated Asset Recovery

Where identifiable, customers are charged for the use of assets and associated investment as dedicated to their individual supply. The pricing components included are:

- Dedicated transformer charge;
- Dedicated lines charge;
- Control relay charge;

[5] www.thelinescompany.co.nz/customers/pricing-and-billing

- Pole mounting charge for streetlights.

Customers who pay for the capacity provided by a dedicated transformer, are charged a lower network price. The high voltage network charge recovers less of the shared cost of supply. The transformer to which they are connected is dedicated to their use, and their connection is deemed to be to the high voltage distribution network. This price differential is shown on the pricing schedule as high and low voltage.

2.4.3. Low Fixed Charge

Under the Low Fixed Charge regulations, TLC has an obligation to provide a Regulated Distributor tariff option to consumers in their principal place of residence. This tariff (Low Fixed Charge Plan) must have a fixed charge of no more than 15 cents per day, and the sum of fixed and variable charges must be such that, for the average consumer, this tariff is not more than any alternative tariff offered. The requirement to offer such a tariff option, and the resulting subsidy, is acknowledged in section (a) (i) of the Pricing Principles.

Eligibility for this tariff is based on the definition of an "average consumer". The regulations define an average consumer as a customer in their primary place of residence with annual consumption below 8,000kWh (9,000kWh for applicable South Island regions). As the regulations do not define an average customer with regards to load, TLC has determined an average consumer for application of this Pricing Methodology. Explanation and supporting data for this have been provided to the EA under disclosure requirements in the regulations. (Reg. 23(d)). For the period 1 April 2017 to 31 March 2018, the average consumer has a kW load of 2.65kW.

2.4.4. Service fees

Other pricing components used to recover target revenue are:

- Account fees;
- De-energisation and re-energisation charges.

These charges recover the dedicated provision of the respective service.

2.4.5. Transmission charges

The transmission charge recovers the cost of transmission and pass-through costs payable as levies and rates.

Customers with capacity requirements less than 100 kVA (SUP and LFCP) contribute to recoverable and pass-through costs through a single variable transmission charge based on the same billed quantity as the kW Load charge.

Large capacity customers on the MUP have two transmission charges:

- Connection Charge – recovers a portion of the connection charge from Transpower plus pass-through;
- Individual Peak Demand or Co-incidental Demand (with the LNI 100 highest peaks) – based on either, the average of the highest six, two hour peaks recorded at the installation over the previous year; or the load co-incidental with Transpower's top 100 LNI peaks where an installation may make a significant impact on LNI RCPD. The decision to recover transmission

and pass-through from MUP using anytime peaks is that the load patterns of these consumers have a greater singular impact on network constraints.

2.4.6. Price Changes

Target Revenue recovered from standard contract customers has increased by 3.1% from the preceding year. Table 7 shows the target revenue allocated by pricing component for standard contracts. The price component allocation is made in line with current methodology and excludes revenue earned from non-standard contracts.

Standard Contracts - Target Revenue and Price Components				
		2016	2017	2017
Cost	Key Price Component	$m	$m	% of Total
Distribution	Fixed Capacity Charges	$ 8.3	$ 9.3	25%
	Variable Demand Charges	$ 17.0	$ 17.1	47%
	Dedicated Asset Charges	$ 3.4	$ 3.7	10%
	Low Fixed Charges	$ 0.4	$ 0.4	1%
	Service Fees	$ 0.2	$ 0.2	0%
Recoverable and Pass through	Transmission Charges	$ 6.1	$ 5.9	16%
Total		$ 35.4	$ 36.5	100%

Table 7: 2017 Price Changes

3. Non-Standard Contract Pricing Methodology

3.1. Non-Standard Contracts

TLC currently has 14 customers connected to its network on non-standard contracts. The rationale for using a non-standard contract is based on the cost of the assets dedicated (substantially dedicated) to the provision of the connection and the service levels required to maintain supply at the connection.

Non-Standard Contracts - Target Revenue and Price Components					
Non-Standard Contracts	No. of Customers	Revenue 2016	Revenue 2017	2017 - % of Target Revenue earned from Key Pricing Components	
		$m	$m	Distribution	Transmission
Total	14	$ 6.1	$ 6.2	72%	28%

Table 8: Non-Standard Contract Statistics

Shared network and transmission costs are recovered as per standard contracts. Typically a non-standard contract customer will require a capacity over 100kVA.

The price charged for the dedicated assets will be driven by:

- An asset maintenance cost based on the costs to maintain the dedicated assets. It includes a charge based on the line length of the dedicated asset multiplied by the relevant rate per km;
- A value related cost to earn a rate of return on the Regulatory Asset Value of the dedicated assets during the regulatory return period;
- A recovery of the capital cost to reflect depreciation of the asset during the contract term. The estimated value of the assets at the end of the current contract period is influenced significantly by the likelihood of the operation continuing beyond the contact period, or the assets being of value on contract expiry;
- Customer related costs, depending upon the time commitment and frequency of interaction, required to maintain the contractual relationship.

3.1.1. Pricing Principles alignment

The non-standard contract methodology aligns with the Pricing Principles in that:

- It prices on the basis of being subsidy free (equal to or greater than incremental costs, and less than or equal to standalone costs);
- It has regard to the level of available service capacity;
- Prices are set with regard to consumers' demand responsiveness.

Prices are responsive to the requirements and circumstances of stakeholders to discourage uneconomic bypass.

3.2. Supply obligation

There is no specific obligation that would increase the supply obligation in a non-standard contract. However, an increased level of service is implicit when dedicated assets are installed as part of the infrastructure requirements.

4. Distributed Generation Pricing Methodology

Prices charged and payments made to Generators on TLC's network are in accordance with the intent of Part 6: Connection of Distributed Generation of the Electricity Industry Participation Code 2010 and the pricing principles outlined in that document. The code has different regulations for injection, less than and greater than 10kW.

4.1. Distributed Generation Charges

Distributed Generators, at the point of connection, may be charged a:

- Network Charge based on capacity requirements;
- Dedicated Asset charge based on recovery of investment and related costs;
- An administration charge to cover costs associated with the calculation of ACOT payments, general account maintenance, and engineering and other technical costs that relate to distributed generation generally and for specific installations.

4.2. Distributed Generation Payments

Generators may receive payment for the benefit they provide in avoiding transmission charges from Transpower. These ACOT payments are recovered from the interconnection portion of transmission charges made to all customers on TLC's network. Where possible the calculation of this benefit is dependent upon the current methodology used by Transpower to allocate their interconnection charges. Currently, the benefit is calculated as follows:

- The average injection by the generator at the time of each of the top 100 LNI peaks in the preceding year ending 31 August. Where negotiated, ACOT will be paid only if the generator supplies metering data to TLC in a format that can be constantly fed into TLC's network operating system;
- Adjusted by losses between the point of injection into the network and the Transpower POS;
- Multiplied by the charge, per kW, as charged by Transpower.

Appendix 1: Pricing Principles Alignment Table

Pricing Principles		Pricing Methodology Reference
(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	Section 1
	(ii) having regard, to the extent practicable, to the level of available service capacity	Section 1.4
	(iii) signalling, to the extent practicable, the impact of additional usage on future investment costs	
(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 consumers' demand responsiveness, to the extent practicable		Section 2.4.1
(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	Section 3
	(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	Section 1.1 , Section 2.2 , Section 3
	(iii) where network economics warrant, and to the extent practicable, encourage investment in transmission and distribution alternatives and technology innovation	Section 4
(d) Development of prices should be transparent, promote price stability and certainty for stakeholders, and changes to prices should have regard to the impact to stakeholders		Section 1.4
(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		n/a

Appendix 2: Information Disclosure Guidelines Alignment Table

Information Disclosure Guidelines		Pricing Methodology Reference
(a) Prices should be based on a well-defined, clearly explained and published methodology, with any material revisions to the methodology notified and clearly marked		
(b) The pricing methodology disclosed should demonstrate:		
	(i) How the methodology links to the pricing principles and any non-compliance	refer; Alignment table
	(ii) The rationale for consumer groupings and the method for determining the allocation of consumers to the consumer groupings	Section 2.2
	(iii)Quantification of key components of costs and revenues	Section 2
	(iv) An explanation of the cost allocation methodology and the rationale for the allocation to each consumer grouping	Section 2.3
	(v) An explanation of the derivation of the tariffs to be charged to each consumer group and the rationale for the tariff design	Section 2.4
	(vi) Pricing arrangements that will be used to share the value of any deferral of investment in distribution and transmission assets, with the investors in alternatives such as distributed generation or load management, where alternatives are practicable and where network economics warrant.	Section 2.4 , Section 4
(c) The pricing methodology should:		
	(i) Employ industry standard terminology, where possible	Abbreviations
	(ii) Where a change to the previous pricing methodology is implemented, describe the impact on consumer classes and the transition to introduce the new methodology	Section 1.3

Appendix 3: Information Disclosure Determination 2012 Alignment Table

Information Disclosure Determination 2012 requirements	Price Methodology Reference
Section 2.4.1 Every EDB must publically disclose, before the start of each pricing year, a pricing methodology which- (4) Explains whether, and if so how, the EDB has sought the **views of consumers**, including their expectations in terms of price and quality, and reflected those views in calculating the prices payable or to be payable. If the EDB has not sought the views of consumers, the reasons for not doing so must be disclosed.	Section 1.1
Section 2.4.3 Every disclosure under clause 2.4.1 above must- **(1)** Include sufficient information and commentary to enable interested persons to understand how **prices** were set for each consumer group, including the assumptions and statistics used to determine prices for each consumer group	Section 2.3
(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	refer Alignment table
(3) State the **target revenue** expected to be collected for the disclosure year to which the pricing methodology applies	Section 2.4, Section 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	Section 2.1
(5) State the **consumer groups** for whom the prices have been set, and describe - **(a)** the rationale for grouping consumers in this way **(b)** the method and the criteria used by the EDB to allocate consumers to each of the consumer groups	Section 2.2
(6) If **prices have changed** from prices disclosed for the immediately preceding disclosure year, explain the reasons for changes, and quantify the difference in respect of each of those reasons	Section 2.4.6
(7) Where applicable, describe the method used by the EDB to **allocate the target revenue** among consumer groups, including the numerical values of the target revenue allocated to each consumer group, and the rationale for allocating it in this way	Section 2.3
(8) State the **proportion of target revenue** (if applicable) that is collected through each price component as publicly disclosed under clause 2.4.18	Section 2.4, Section 3

Appendix 3: Information Disclosure Determination 2012 Alignment Table (continued)

Information Disclosure Determination 2012 requirements	Price Methodology Reference
Section 2.4.4 Every disclosure under clause 2.4.1 above must, if the EDB has a **pricing strategy** - **(1)** Explain the pricing strategy for the next 5 disclosure years (or as close to 5 years as the pricing strategy allows), including the current disclosure year for which prices are set **(2)** Explain how and why prices for each consumer group are expected to change as a result of the pricing strategy **(3)** If the pricing strategy has changed from the preceding disclosure year, identify the changes and explain the reasons for the changes	Section 1.4
Section 2.4.5 Every disclosure under clause 2.4.1 above must- **(1)** Describe the approach to setting prices for **non-standard contracts**, including- **(a)** the extent of non-standard contract use, including the number of ICPs represented by non-standard contracts and the value of target revenue expected to be collected from consumers subject to non-standard contracts **(b)** how the EDB determines whether to use a non-standard contract, including any criteria used **(c)** any specific criteria or methodology used for determining prices for consumers subject to non-standard contracts and the extent to which these criteria or that methodology are consistent with the pricing principles.	Section 3
(2) Describe the EDB's obligations and responsibilities (if any) to consumers subject to non-standard contracts in the event that the **supply of electricity lines services to the consumer is interrupted**. This description must explain- **(a)** the extent of the differences in the relevant terms between standard contracts and non- standard contracts **(b)** any implications of this approach for determining prices subject to non-standard contracts	Section 3.3
(3) Describe the EDB's approach to developing prices for electricity distribution services provided to consumers that own **distributed generation,** including any payments made by the EDB to the owner of any distributed generation, and including the- **(a)** prices; and **(b)** value, structure and rationale for any payments to the owner of the distributed generation.	Section 4

Appendix 4: Director's Certification - Schedule 17

Schedule 17 Certification for Year-beginning Disclosure

Clause 2.9.1 of section 2.9

We, Mark Charles DARROW and Peter John TILL, being directors of The Lines Company Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

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

b) The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

31 March 2017	31 March 2017
Date	Date
Mark Charles DARROW	**Peter John TILL**
Chairman	Director

Appendix 5: Schedule of Prices 2017

The Lines Company Limited

Schedule of Prices

1 April 2017

The Lines Company Limited Delivery Prices																						
Effective 1 April 2017 (excl. GST)																						
Pursuant to requirements of the Electricity Distribution Information Disclosure Determination 2012. Commencement date: 1 April 2017.																						
Consumer Group	Forecast number of ICPs as at 1 April 2017	Delivery Prices																				
		Distribution Prices									Transmission Prices											
		Fixed						Variable			Variable											
		Network			Low Fixed Charge			kW Load			Transmission			Connection			Individual Peak demand			Co-incidental demand		
Hangatiki		Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD
Low Fixed Charge Plan					$/month			$/kW/month			$/kW/month											
High Density/Low Voltage	1,877				5.07	5.07	4.56	24.52	25.71	23.14	6.84	6.40	5.76									
Low Density/Low Voltage	264				5.07	5.07	4.56	31.82	33.33	30.00	6.84	6.40	5.76									
High Density/High Voltage	296				5.07	5.07	4.56	20.32	21.31	19.18	6.84	6.40	5.76									
Low Density/High Voltage	368				5.07	5.07	4.56	23.86	25.01	22.51	6.84	6.40	5.76									
Standard User Plan		$/kVA/month						$/kW/month			$/kW/month											
High Density/Low Voltage	2,913	4.18	4.37	3.93				18.55	19.38	17.44	6.84	6.40	5.76									
Low Density/Low Voltage	822	8.05	8.41	7.57				18.55	19.38	17.44	6.84	6.40	5.76									
High Density/High Voltage	1,111	1.95	2.04	1.84				18.55	19.38	17.44	6.84	6.40	5.76									
Low Density/High Voltage	1,293	3.83	4.00	3.60				18.55	19.38	17.44	6.84	6.40	5.76									
Major User Plan		$/kVA/annum												$/kVA/annum			$/kVA/annum			$/kVA/annum		
400 V		120.45	125.87	113.28										16.64	2.73	2.46	65.44	74.07	66.66			
11 kV		114.14	119.28	107.35										16.64	2.73	2.46	65.44	74.07	66.66			
33 kV	19	69.25	72.37	65.13										16.64	2.73	2.46	65.44	74.07	66.66			
Stepped		85.62	89.47	80.52										16.64	2.73	2.46	65.44	74.07	66.66			
Co-incidental demand																				131.32	145.01	130.51
Whakamaru		Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD
Low Fixed Charge Plan					$/month			$/kW/month			$/kW/month											
High Density/Low Voltage	307				5.07	5.07	4.56	30.78	32.26	29.03	1.15	1.05	0.95									
Low Density/Low Voltage	85				5.07	5.07	4.56	36.91	38.65	34.79	1.15	1.05	0.95									
High Density/High Voltage	23				5.07	5.07	4.56	26.57	27.86	25.07	1.15	1.05	0.95									
Low Density/High Voltage	235				5.07	5.07	4.56	29.57	30.99	27.89	1.15	1.05	0.95									
Standard User Plan		$/kVA/month						$/kW/month			$/kW/month											
High Density/Low Voltage	496	4.18	4.37	3.93				24.81	25.93	23.34	1.15	1.05	0.95									
Low Density/Low Voltage	315	7.43	7.76	6.98				24.81	25.93	23.34	1.15	1.05	0.95									
High Density/High Voltage	62	1.95	2.04	1.84				24.81	25.93	23.34	1.15	1.05	0.95									
Low Density/High Voltage	940	3.54	3.70	3.33				24.81	25.93	23.34	1.15	1.05	0.95									
Major User Plan		$/kVA/annum															$/kVA/annum			$/kVA/annum		
400 V		120.45	125.87	113.28													13.75	12.61	11.35			
11 kV		216.05	225.77	203.19													13.75	12.61	11.35			
33 kV	1	69.25	72.37	65.13													13.75	12.61	11.35			
Stepped		85.62	89.47	80.52													13.75	12.61	11.35			
Co-incidental demand																				131.32	145.01	130.51

The Lines Company Limited Delivery Prices																						
Effective 1 April 2017 (excl. GST)																						
Pursuant to requirements of the Electricity Distribution Information Disclosure Determination 2012. Commencement date: 1 April 2017.																						
Consumer Group	Forecast number of ICPs as at 1 April 2017	Delivery Prices																				
		Distribution Prices									Transmission Prices											
		Fixed						Variable			Variable											
		Network			Low Fixed Charge			kW Load			Transmission			Connection			Individual Peak demand			Co-incidental demand		
Ohakune		Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD
Low Fixed Charge Plan					$/month			$/kW/month			$/kW/month											
High Density/Low Voltage	312				5.07	5.07	4.56	21.20	22.24	20.02	6.93	7.46	6.71									
Low Density/Low Voltage	0				5.07	5.07	4.56	25.01	26.22	23.60	6.93	7.46	6.71									
High Density/High Voltage	44				5.07	5.07	4.56	16.97	17.82	16.04	6.93	7.46	6.71									
Low Density/High Voltage	0				5.07	5.07	4.56	18.84	19.77	17.79	6.93	7.46	6.71									
Standard User Plan		$/kVA/month						$/kW/month			$/kW/month											
High Density/Low Voltage	1,447	4.20	4.39	3.95				15.19	15.87	14.28	6.93	7.46	6.71									
Low Density/Low Voltage	0	6.22	6.50	5.85				15.19	15.87	14.28	6.93	7.46	6.71									
High Density/High Voltage	172	1.96	2.05	1.85				15.19	15.87	14.28	6.93	7.46	6.71									
Low Density/High Voltage	0	2.95	3.08	2.77				15.19	15.87	14.28	6.93	7.46	6.71									
Major User Plan		$/kVA/annum												$/kVA/annum			$/kVA/annum			$/kVA/annum		
400 V	0	120.45	125.87	113.28										19.46	21.47	19.32	63.74	68.06	61.25			
11 kV		124.89	130.51	117.46										19.46	21.47	19.32	63.74	68.06	61.25			
33 kV		69.25	72.37	65.13										19.46	21.47	19.32	63.74	68.06	61.25			
Stepped		85.62	89.47	80.52										19.46	21.47	19.32	63.74	68.06	61.25			
Co-incidental demand																				131.32	145.01	130.51
Ongarue		Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD
Low Fixed Charge Plan					$/month			$/kW/month			$/kW/month											
High Density/Low Voltage	1,162				5.07	5.07	4.56	25.48	26.71	24.04	7.99	8.94	8.05									
Low Density/Low Voltage	223				5.07	5.07	4.56	32.82	34.37	30.93	7.99	8.94	8.05									
High Density/High Voltage	124				5.07	5.07	4.56	21.25	22.30	20.07	7.99	8.94	8.05									
Low Density/High Voltage	211				5.07	5.07	4.56	24.80	26.00	23.40	7.99	8.94	8.05									
Standard User Plan		$/kVA/month						$/kW/month			$/kW/month											
High Density/Low Voltage	1,624	4.21	4.40	3.96				19.45	20.33	18.30	7.99	8.94	8.05									
Low Density/Low Voltage	373	8.10	8.46	7.61				19.45	20.33	18.30	7.99	8.94	8.05									
High Density/High Voltage	356	1.97	2.06	1.85				19.45	20.33	18.30	7.99	8.94	8.05									
Low Density/High Voltage	555	3.85	4.02	3.62				19.45	20.33	18.30	7.99	8.94	8.05									
Major User Plan		$/kVA/annum												$/kVA/annum			$/kVA/annum			$/kVA/annum		
400 V	1	120.45	125.87	113.28										23.54	25.78	23.20	72.33	81.44	73.30			
11 kV		129.41	135.23	121.71										23.54	25.78	23.20	72.33	81.44	73.30			
33 kV		69.25	72.37	65.13										23.54	25.78	23.20	72.33	81.44	73.30			
Stepped		85.62	89.47	80.52										23.54	25.78	23.20	72.33	81.44	73.30			
Co-incidental demand																				131.32	145.01	130.51

The Lines Company Limited Delivery Prices																						
Effective 1 April 2017 (excl. GST)																						
Pursuant to requirements of the Electricity Distribution Information Disclosure Determination 2012. Commencement date: 1 April 2017.																						
Consumer Group	Forecast number of ICPs as at 1 April 2017	Delivery Prices																				
		Distribution Prices									Transmission Prices											
		Fixed						Variable			Variable											
		Network			Low Fixed Charge			kW Load			Transmission			Connection			Individual Peak demand			Co-incidental demand		
National Park		Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD
Low Fixed Charge Plan					$/month			$/kW/month			$/kW/month											
High Density/Low Voltage	91				5.07	5.07	4.56	26.82	28.12	25.31	11.01	11.32	10.19									
Low Density/Low Voltage	38				5.07	5.07	4.56	31.38	32.89	29.60	11.01	11.32	10.19									
High Density/High Voltage	19				5.07	5.07	4.56	21.78	22.85	20.57	11.01	11.32	10.19									
Low Density/High Voltage	34				5.07	5.07	4.56	24.00	25.17	22.65	11.01	11.32	10.19									
Standard User Plan		$/kVA/month						$/kW/month			$/kW/month											
High Density/Low Voltage	297	5.03	5.26	4.73				19.24	20.11	18.10	11.01	11.32	10.19									
Low Density/Low Voltage	152	7.45	7.79	7.01				19.24	20.11	18.10	11.01	11.32	10.19									
High Density/High Voltage	53	2.36	2.47	2.22				19.24	20.11	18.10	11.01	11.32	10.19									
Low Density/High Voltage	119	3.54	3.70	3.33				19.24	20.11	18.10	11.01	11.32	10.19									
Major User Plan		$/kVA/annum												$/kVA/annum			$/kVA/annum			$/kVA/annum		
400 V	2	120.45	125.87	113.28										43.04	47.96	43.16	89.03	87.82	79.04			
11 kV		166.08	173.55	156.20										43.04	47.96	43.16	89.03	87.82	79.04			
33 kV		69.25	72.37	65.13										43.04	47.96	43.16	89.03	87.82	79.04			
Stepped		85.62	89.47	80.52										43.04	47.96	43.16	89.03	87.82	79.04			
Co-incidental demand																				131.32	145.01	130.51
Tokaanu		Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD	Previous	Current	After PPD
Low Fixed Charge Plan					$/month			$/kW/month			$/kW/month											
High Density/Low Voltage	1,205				5.07	5.07	4.56	23.70	24.86	22.37	5.36	6.06	5.45									
Low Density/Low Voltage	10				5.07	5.07	4.56	31.04	32.52	29.27	5.36	6.06	5.45									
High Density/High Voltage	23				5.07	5.07	4.56	19.49	20.46	18.41	5.36	6.06	5.45									
Low Density/High Voltage	20				5.07	5.07	4.56	23.04	24.16	21.74	5.36	6.06	5.45									
Standard User Plan		$/kVA/month						$/kW/month			$/kW/month											
High Density/Low Voltage	3,291	4.20	4.39	3.95				17.69	18.49	16.64	5.36	6.06	5.45									
Low Density/Low Voltage	33	8.09	8.45	7.61				17.69	18.49	16.64	5.36	6.06	5.45									
High Density/High Voltage	108	1.97	2.06	1.85				17.69	18.49	16.64	5.36	6.06	5.45									
Low Density/High Voltage	83	3.85	4.02	3.62				17.69	18.49	16.64	5.36	6.06	5.45									
Major User Plan		$/kVA/annum												$/kVA/annum			$/kVA/annum			$/kVA/annum		
400 V	6	120.45	125.87	113.28										8.77	10.65	9.59	55.57	62.10	55.89			
11 kV		125.01	130.64	117.58										8.77	10.65	9.59	55.57	62.10	55.89			
33 kV		69.25	72.37	65.13										8.77	10.65	9.59	55.57	62.10	55.89			
Stepped		85.62	89.47	80.52										8.77	10.65	9.59	55.57	62.10	55.89			
Co-incidental demand																				131.32	145.01	130.51

The Lines Company Limited Common Prices, Fees and Charges
Effective 1 April 2017 (excl. GST)

Pursuant to requirements of the Electricity Distribution Information Disclosure Determination 2012

Charge Type	Commencement Date	Forecast number of ICPs as at 1 April 2017			
Dedicated Transformer Charge			Previous	Current	After PPD
Billing Code			$/month		
T5	1 April 2017	2,624	25.97	27.14	24.43
T10		1,200	43.10	45.04	40.54
T15		1,814	59.04	61.70	55.53
T30		226	78.20	81.72	73.55
T50		196	86.66	90.56	81.50
T75		112	105.73	110.49	99.44
T100		53	118.17	123.49	111.14
T200		24	203.65	212.81	191.53
T300		11	245.79	256.85	231.17
T500		17	287.78	300.73	270.66
T750		7	345.46	361.01	324.91
T1000		2	389.49	407.02	366.32
T1250		1	411.50	430.02	387.02
T1500		3	463.26	484.11	435.70

Charge Type	Commencement Date	Forecast number of ICPs as at 1 April 2017			
Dedicated Lines Charges			Previous	Current	After PPD
Line Type			$/month		
11kV 3 phase o/head (>50mm<150mm)	1 April 2017	2	0.62	0.65	0.59
11kV 3 phase o/head (<50mm)			0.53	0.55	0.50
11kV single phase			0.45	0.47	0.42
11kV single phase SWER			0.40	0.42	0.38
400V 4 wire system			0.73	0.76	0.68
400V 2&3 wire system			0.59	0.62	0.56
400V underbuilt 4 wire			0.38	0.40	0.36
400V underbuilt 2&3 wire			0.34	0.36	0.32
11kV cables (>50mm<240mm)			1.65	1.72	1.55
11kV cables (<50mm)			1.36	1.42	1.28
400V 3&4 wire heavy (>240mm)			1.27	1.33	1.20
400V 3&4 wire medium (<240mm)			1.06	1.11	1.00
400V 2&3 wire light			0.62	0.65	0.59

The Lines Company Limited Common Prices, Fees and Charges
Effective 1 April 2017 (excl. GST)

Pursuant to requirements of the Electricity Distribution Information Disclosure Determination 2012

Charge Type	Commencement Date	Forecast number of ICPs as at 1 April 2017	Previous	Current	After PPD
Relay Fees			$/Unit/month		
	1 April 2017	17,022	1.72	1.79	1.61
Streetlight Charges			$/pole/month		
For streetlights mounted on poles belonging to The Lines Company		6	4.70	4.91	4.42

The Charges for Streetlights comprise:

1/ For those on a dedicated streetlight circuit;

a. An asset charge based on the value of the streetlight circuit as per the dedicated line charge, plus

b. the charges applicable to half-hour customers.

2/ For other lights, the charges applicable to non half-hour customers.

3/ For streetlights mounted on power poles forming part of The Lines Company network, an additional charge per month per pole

4/ The standard load shifting and control charges where those services are supplied.

Billing Charge		33	$/month		
			147.70	154.35	138.92

applicable to customers on the Major User Plan

Load Shifting Charge		10	$/plant operation		
			2.61	2.73	2.46

De-Energisation and Re-Energisation Schedule
Travel and cost incurred
Prompt Payment Discount not applicable

	The Lines Company has depots at the following towns; Te Kuiti, Taumarunui, Turangi & Ohakune. The following measurements are from these depots. Otorohanga is included in Urban A.	Urban A	Rural B	Remote C	Special D
		Inside 50 km/h zone.	Up to 25 kms from depot.	Over 25 kms from depot.	Door Knock Request
		$	$	$	$/request
1	**EARLY - NEXT DAY:** Job request by 2:00 pm and executed next working day by 4:30 pm.	46.58	58.22	174.66	60.00**
	Previous Charges	46.58	58.22	174.66	60.00
2	**LATE - NEXT DAY**: Job request after 2:00 pm executed next working day by 4:30 pm.	52.40	64.05	203.77	** Additional charge if no contact is made by customer prior to 2 working days before De-energisation. Further charges of $15 per 10 minute blocks apply if staff member is onsite and required to wait whilst customer contacts The Lines Company or Energy Retailer for extension of payment.
	Previous Charges	52.40	64.05	203.77	
3	**SAME DAY:** Job request for same working day before 3:00 pm and executed that day.	69.86	81.51	261.99	
	Previous Charges	69.86	81.51	261.99	
4	**AFTER HOURS:** Re-energisation request only. From 3:00 pm onwards on any given weekday, weekend or public holiday before 10:00 pm.	116.44	174.66	349.31	
	Previous Charges	116.44	174.66	349.31	
5	**AFTER HOURS:** Re-energisation request only. After 10:00 pm on any given day including public holidays.	232.88	291.09	523.97	
	Previous Charges	232.88	291.09	523.97	
7	**CANCELLATION FEE:** Applies if request 1(a,b,c) is cancelled between 2:00-4:00pm on day prior to scheduled action. If cancellation after 4:00 pm then full charge applies.	36.23	47.87	164.31	
	Previous Charges	36.23	47.87	164.31	

- The disclosure of this document is in accordance with Section 2.4.1 of the Information Disclosure Determination 2012.

- The development of this methodology is in alignment with the Pricing Principles developed by the Electricity Authority, in accordance with statutory objectives defined in the Electricity Industries Act 2010.

- The Pricing Methodology employed by The Lines Company Limited recovers regulated income under the Default Price Quality Path as prescribed by Commerce Commission Input Methodology Determination 2012.

- The disclosure year is 1 April 2017 to 31 March 2018.