networktasman

Your consumer-owned electricity distributor

PRICING METHODOLOGY DISCLOSURE

For Year Commencing 1 April 2016

Pursuant to Electricity Distribution Information Disclosure Determination (Issued 1 October 2012). For compliance with Part 2.4: Disclosure of Pricing and Related Information.

Network Tasman Limited

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Contents

1 Introduction

1.1 About Network Tasman

Network Tasman Limited (NTL) owns and operates the electricity distribution network in the wider Nelson and Tasman areas, excluding Nelson Electricity's supply area in Nelson city. The Network Tasman electricity distribution network distributes power to approximately 38,000 connections in an area of 10,800 sq km in the northwestern corner of the South Island.

Total electricity distributed through the network is 593 GWh, with a peak load of 119 MW.[1] The area covered by the network is diverse, ranging from high consumer density urban areas to remote rural areas with low consumer density.

NTL distributes electricity to residential and commercial consumers within its area from Transpower grid exit points at Stoke, Kikawa and Murchison.

NTL's mission is to operate low cost, open access networks that deliver outstanding reliability and efficiency while maintaining shareholder value. NTL issues, after consultation with its shareholders, an annual statement of corporate intent, which outlines the overall intentions and objectives that the company will follow.

NTL is wholly owned by a consumer trust - the Network Tasman Trust.

1.2 The purpose of this document

This document has been prepared by NTL for the purposes of compliance with Part 2.4 of the Electricity Distribution Information Disclosure Determination 2012. It also assesses NTL's pricing methodology against the Distribution Pricing Principles and Information Disclosure Guidelines published by the Electricity Authority ("EA").

1.3 Network Tasman pricing from 1 April 2016

NTL's pricing for its distribution network for the 12 months beginning 1 April 2016 is the same as what it was during the prior 12 month period. NTL's transmission charges have increased by around 2% reflecting increased Transpower charges. The result for an average residential consumer is a 0.6% total network charge increase, adding around 32 cents per month or $3.80 annually.

Appendix B contains a complete list of NTL's prices for the 12 months commencing 1 April 2016, as compared with pricing for the prior year.

The methodology that NTL has used to determine pricing for the 12 months commencing 1 April 2016 is the same as what was used for the previous year.

1.4 Overview of this report

This document is structured as follows:

- The regulatory requirements that NTL must comply with are set out in section 2;
- The source of the financial information relied on is explained in section 3;

[1] Excluding bulk supply.

- NTL's pricing principles and strategy are discussed in section 4;
- The methodology used to derive NTL's distribution prices is set out in section 5;
- The methodology used to derive NTL's transmission prices is detailed in section 6
- Distributed generation is addressed in section 7; and
- Assessment of NTL's pricing methodology against the EA's Pricing Principles and Information Disclosure Guidelines is set out in section 8.

2 REGULATORY REQUIREMENTS

This section briefly describes a number of key regulations relating to the NTL's pricing. Namely information disclosure, Commerce Act price-quality controls and the Low Fixed Charge (LFC) Regulations.

2.1 Information Disclosure Determination

The Electricity Distribution Information Disclosure Determination 2012 (Part 2.4) gazetted by the NZ Commerce Commission requires electricity line businesses (EDBs) to annually disclose:

- the EDB's pricing strategy, if any, including identification of any changes in strategy
- the pricing methodology used to calculate line prices
- key components of target revenue required to cover the costs and profits, (including cost of capital and transmission), of the line owner's business activities
- consumer groups and consumer statistics used in the calculation of line prices and charges
- the method of allocating costs and target revenues amongst consumer groups
- the proportion of target revenue collected through each pricing component.
- any changes to prices or target revenues
- the approach to setting prices for non-standard contracts and distributed generators
- the extent to which the pricing methodology is consistent with the Electricity Authority's pricing principles

The Electricity Authority (EA) has published Distribution Pricing Principles and Information Disclosure Guidelines (February 2010) that promote a principles-based approach to EDB line pricing and associated information disclosures. The EA's guidelines are generally consistent with the Information Disclosure Determination 2012.

2.2 Commerce Act Price Control

NTL is a controlled entity under Part 4 of the Commerce Act and as such operates under the Commerce Commission's Default Price and Quality control.

Being a controlled entity NTL is subject to starting price adjustments (Po) at the commencement of each regulatory period and must annually demonstrate compliance with its Default Price Path (DPP) that allows certain costs (transmission, rates, EA and Commerce Commission levies) to be passed through to consumers and generally restricts annual

movements for the distribution component of line prices after each P_0 reset to the annual rate of inflation (CPI).

The Commerce Commission price control primarily operates to constrain NTL's overall target revenue requirement rather than the structure of the company's line prices.

NTL's distribution revenue requirement shown in this document is set to be compliant with NTL's DPP price pathway requirements as at 31 March 2017.

2.3 Low Fixed Charge Regulations

Under the Low Fixed Charge (LFC) regulations a distributor's fixed charge to eligible ICPs must be no more than 15 cents per day (ex GST) for the LFC tariff option and a retailer's fixed charge must be no more than 30 cents per day (ex GST). The LFC option must be available to all domestic connections that are a principal place of residence, where annual consumption is less than 8000 kWh.

A fixed charge is defined in the regulations to be "a charge levied for each customer connection in currency per time period (for example, cents per day)". A variable charge is defined as "a charge that varies according to the amount of electricity consumed (for example, cents per kilowatt hour)."

3 FINANCIAL INFORMATION

This pricing disclosure relies on financial information drawn from NTL's line business budget and financial forecasts for the year ending 31 March 2017. Line business costs are separated from NTL's other non-line business activities in a manner consistent with the Electricity Information Disclosure Determination 2012 .

The forecast financial information provides the transmission, operating, maintenance, depreciation and overhead cost estimates used to determine NTL's line business target revenue requirement.

Network capital costs are based on:

- The Commerce Commission's estimate of WACC for EDB's subject to DPP control for the 5 year period between 2016 and 2020, and
- NTL's forecast Regulatory Asset Base (RAB) to be included in Information Disclosures as at 31 March 2016.

The RAB is based on the 2004 certified ODV of systems fixed assets and has been rolled forward to 31 March 2016 using the methodology inherent in the Information Disclosure Determination. The roll forward includes actual capital expenditure at cost, depreciation based on standard regulatory asset lives and CPI based system fixed asset revaluations for the intervening period to 31 March 2016.

4 PRICING PRINCIPLES & STRATEGY

NTL's pricing methodology reflects, to the extent possible:

- The pricing principles stated in NTL's Statement of Corporate Intent (**"SCI"**) as agreed between NTL and its shareholder; Network Tasman Trust.

- The Distribution Pricing Principles and Information Disclosure Guidelines (February 2010) administered by the NZ Electricity Authority.

The following pricing objectives are stated in NTL's SCI (available on NTL's website) and are incorporated in Use of Systems Agreements with retailers. They provide a high level overview of NTL's forward pricing strategy:

- A fair and reasonable rate of return for shareholders (equal to the cost of capital measured on a pre-tax, pre-discount basis and based on the regulators WACC) will be recovered
- The cost of capital will be reasonably allocated to, and recovered from, each consumer group based on their use of particular network assets.
- Direct and indirect distribution costs and depreciation will be reasonably allocated to, and recovered from, each consumer group
- Transmission costs will be allocated and recovered in a manner that reasonably reflects how these costs are incurred by each consumer group
- Appropriate economic signals will be given to consumers concerning their use of the distribution and transmission systems
- Regulatory and public policy requirements imposed by Government, the Commerce Commission and the Electricity Authority will be accommodated within network pricing as required
- Pricing will retain a reasonable uniformity amongst like consumers and across all NTL's regional areas.
- Pricing will be simple to understand, implement and administer
- Pricing will provide certainty and medium term stability for consumers and retailers. The distribution component of pricing will be changed, at most, once in any 12 month period while the transmission component may change whenever Transpower alters its transmission charges.

While these objectives have been in place for the last 5 years and are expected to endure into the future, they remain subject to annual review by NTL Directors and Network Tasman Trust as part of the SCI process.

The specific pricing principles published in EA Guidelines are stated in Section 23 and are also viewable at:

> http://www.ea.govt.nz/our-work/programmes/transmission-work/principles-or-model-approaches-to-distribution-pricing/

Where pricing objectives or principles are in conflict, NTL Directors exercise their discretion and judgement to set acceptable trade-offs between conflicting items.

5 PRICING FOR DISTRIBUTION SERVICES

The derivation of distribution pricing links costs to prices by allocating costs to load groups and then calculating tariffs for those load groups. The stages involve:

- Determination of NTL's total Distribution Revenue Requirement
- Identification of Load Groups
- Allocation of the Distribution Revenue Requirement to Load Groups
- Derivation of Distribution Prices for Load Groups

5.1 NTL's Distribution Revenue Requirement

The Distribution Revenue Requirement for an EDB is the sum of:

- operating & maintenance costs
- overhead costs
- return of capital employed (depreciation)
- return on capital employed (WACC)

NTL accumulates distribution costs listed above using the financial information described in section 3 into the following classifications:

- Direct network costs (directly attributable to specific assets) which include operations and maintenance costs and any direct overheads
- Indirect network costs (not directly attributable to specific assets) which include indirect overheads and administration costs
- Depreciation (return of capital) - based on standard regulatory asset lives for systems assets and financial reporting lives for non-system assets
- Capital costs (return on capital/assets employed) - calculated by applying WACC to NTL's RAB

The sum of these costs equates to the line business's total Distribution Revenue Requirement and its upper bound is constrained by the DPP and P_0 controls administered by the Commerce Commission.

Information on NTL's 2016-17 Distribution Revenue Requirement by cost classification and load group is provided in Appendix A.

The allowable return on capital is represented by the weighted average cost of capital (WACC) for the distribution business and covers the cost of debt (interest costs) and the cost of equity finance. The annual cost of capital is obtained by multiplying the pre-tax WACC by the RAB and non-system asset values allocated to each load group. The non-system asset values are based on their financial reporting book values.

The weighted average cost of capital (WACC) is derived using the Capital Asset Pricing Model. For the financial year commencing 1 April 2016 NTL, as a price controlled EDB, has used the Commerce Commission's WACC for the 5 year DPP price control period ending 31 March 2020. The parameters used by the Commission in setting WACC were:

- 4.09% for estimate of the risk free rate
- Target capital structure of 44% debt to total assets
- Cost of debt 6.09%

- Asset beta of 0.34 as the measure of EDB's systematic risk
- post tax market risk premium for equity of 7.0%
- corporate tax rate of 28.0%

Based on these inputs the Commission's 67th percentile estimate of WACC was 7.19% post tax. NTL has applied an average pre-tax WACC of 9.32% to its line business assets (RAB) in determining DRR.

5.2 Load Groups

NTL's Distribution Revenue Requirement is allocated to consumer load groups and then distribution prices are derived for ICP's (Installation Control Points) within those consumer load groups.

The allocation of ICP's to load groups is determined according to the service levels required by customers at their specific ICP's, namely by the:

- maximum capacity/demand an ICP can place on the network
- use/reliance an ICP places on particular network segments
- type of metering installed at an ICP

Consumer ICP's are classified to load groups as follows:

Consumer Group	Network Segment Used	Maximum capacity requirement
Group 1	General 230/400V / 11 /33kV	Fused <= 15 kVA
Group 2	General 400V / 11 /33kV	Fused > 15 & < 150 kVA
Group 3	Limited 400V and 11 / 33kV	AMD>150kVA+ hhr metering
Group 6	Dedicated & Semi dedicated network, 33 kV &limited 11kV	>= 2000 kVA + 11kV hhr metering
Group CB	66 kV lines	Approx 32MW

Explanation:

- 400V/11/33kV indicates the voltage level at which the consumers in this Group take supply and the components of the network they use.
- The kVA indicates the consumer's potential anytime maximum demand (AMD) as measured by the size of the ICP fuse installed or the AMD obtained from half hourly (hhr) data available from consumer TOU meters.
- Dedicated consumers are those utilising dedicated or semi dedicated feeders, substations and network assets at voltages of at least 11kV or 33kV and have 11kV metering.

Government policy and SCI requirements guide Network Tasman to treat loads on rural spurs lines largely the same as those on the urban mesh network. Consequently load groups, and

therefore distribution charges, are not differentiated across the various geographical areas serviced by the network.

Load group statistics used to allocate costs and calculate prices are provided in Appendix A.

5.3 Allocation of Network Costs to Load Groups

5.3.1 Direct Network Costs, Systems Depreciation and Capital Costs

Direct network costs, systems depreciation and capital costs are directly assignable to the following network asset categories:

- General 400V lines;
- Distribution transformers;
- General 11 kV lines;
- Dedicated 11 kV lines;
- Sub-transmission lines and zone substations; and
- Dedicated networks.

Network costs are then apportioned to each load group on the basis of coincident maximum demand (CMD), calculated at each GXP.

CMD is used because network direct investment and costs are largely a function of peak period demand levels thus critical asset costs are allocated on each groups contribution to peak demand levels.

It is noted that no lower network costs are attributable to load Group 6, as this group relies solely on upper network assets for its supply. Allocations for the 400V cost components are modified to reflect Group 3's minimal reliance on these assets.

With regard to the large embedded generator, the relevant direct network costs are those relating to the 66kV transmission line. The proportion of the 66kV costs allocated to the large embedded generator was set with reference to cost allocation proportions previously used by Transpower.

5.3.2 Allocation of Indirect Network Costs

Indirect network costs include general administration and overhead costs and depreciation on non-systems fixed assets. Management estimates are used to allocate indirect network costs to Group 6, bulk supply and large generator connections. The remaining indirect network costs are allocated to load Groups 1,2 & 3 in proportion to their relative shares of installed capacity (measured by fuse size or dedicated transformer capacity). Allocation of indirect costs is somewhat more arbitrary than for direct costs. However, an allocator based on installed fuse capacity provides a reasonable balance between allocating by customer numbers and allocating by some measure of demand.

5.4 DERIVATION OF DISTRIBUTION TARIFFS.

5.4.1 General

The Distribution Revenue Requirements identify the total costs and thus the distribution revenue to be raised from each load group through distribution tariffs.

Revenue is recovered using "fixed" and "variable" tariff components. Fixed tariffs are either:

- daily charges (expressed as cents/day) or
- capacity/demand based tariffs (expressed as cents/kVA/day).

Variable tariffs are based on consumption or usage (expressed as cents/kWh).

5.4.2 Determining the proportions of fixed and variable tariffs

In determining the proportions of revenue to be raised by fixed and variable tariffs NTL attempts to balance the conflicting demands of:

- economic rationale
- government policy and regulatory requirements
- electricity retailers desire for simplicity, predictability and low transaction costs
- the expectations of different electricity consumers

Economic rationale encourages the application of cost reflective pricing. Regionally differentiated pricing with a strong peak demand / capacity based elements (kVA) and limited reliance of variable tariffs (kWh) would be the logical result. This supports economic efficiency by reflecting in pricing:

- the fixed and sunk nature of line business cost structures and assets
- that network investment costs are caused by demands for incremental capacity at peak times
- a “beneficiaries / exacerbator pays” approach to cost recovery consistent with the EA’s pricing principles.

Government policy and regulations compel distributors to:

- offer to all domestic consumers a 15 cents/day fixed charge tariff option that is beneficial to those with consumption less than 8000 kWh pa.
- ensure rural and urban pricing structures remain closely aligned.

Previous engagement with electricity retailers shows they are focused on line pricing that:

- minimises pass through risk
- minimises transaction costs
- is simple to understand and bill (minimises the number of tariff codes and options).

Consequently retailers have to date generally prefer broad based kWh based charges, simple fixed daily charges and low numbers of tariff codes. However it is noted that looking to future, retailers acknowledge difficulties with a reliance on kWh charges.

NTL engagement with consumers in the past has revealed differing preferences concerning line price structures:

- Many domestic and small business consumers and environmental groups oppose high fixed charge structures and expect a significant portion of their charges to vary with consumption so a greater level of influence can be exerted over their electricity bills.
- Higher-use business consumers however prefer capacity based charging that properly and fairly reflects the fixed costs of supply and rewards high load factor consumers for efficient use of network assets.

As a compromise to the conflicting expectations above, NTL's longer term goal has been to recover around half its distribution revenue from each Group using fixed or capacity base charges and the other half from variable or kWh based charges. Where achievable, over time NTL has raised Group 2 fixed charges in preference to higher variable charges as a better means of reflecting underlying supply costs.

Existing metering technology limitations mean that for about 75% of NTL's ICP's billing metrics are currently restricted to

- kWh consumption in monthly intervals
- installed fuse size or
- fixed daily charges.

For mass market ICPs without advanced meters no metrics are available concerning consumption by time of use or for the level and timing of actual peak or coincident demands. These limited billing metrics compromise cost reflectiveness within tariff structures and make mass market network pricing a relatively blunt instrument.

Consequently NTL has structured its distribution pricing as follows:

- Group 1 fixed charges are set at 15 cents per day (for both small business and residential consumers) to meet government regulatory requirements and to minimise NTL's & retailers' transactions costs. As a consequence of these requirements Group 1 pricing no longer reasonably reflects the fixed costs of supply to poor load factor or remotely located consumers in this group. Just 10% of the revenue collected from Group 1 is derived from fixed daily charges.
- Group 2 tends to have business and domestic consumers with above average load factors and so greater reliance is placed on capacity based pricing applied to installed ICP fuse sizes. Variable tariffs are thus lower than in Group 1. Around 25% of revenue in Group 2 is derived from capacity charges
- Group 3 contains larger, higher load factor business consumers so primary reliance is placed on capacity based pricing using AMD's and RCPD's obtained from TOU metering. Around 50% of the distribution revenue is derived from capacity/ demand based charges.
- Group 6 consumers have fully fixed charges reflecting high levels of asset dedication; they essentially pay an annual fixed rental for the assets dedicated for their supply irrespective of their load profiles.

- There is no tariff differentiation between regional areas and consequently the revenue recovered in rural areas tends not to fully reflect the higher cost of supply to those areas.
- There is no tariff differentiation (either in fixed or variable tariffs) based on consumers end use of electricity (i.e. between business or domestic).

The ongoing deployment of smart meters in NTL's region will significantly improve NTL's ability to implement more sophisticated pricing within the next few years. NTL is currently conducting a detailed pricing review which includes consideration of pricing structures enabled by advanced meters.

5.4.3 Fixed and Capacity based Tariffs by Group

Group 1 ICPs have a single fixed charge expressed as a "cents per day" charge because all ICP's in this Group have a nominal 15 kVA fuse capacity installed to limit the maximum demands each consumer in this Group can place on the network.

Group 2 ICP's have a fixed charge expressed as "dollars per kVA of anytime maximum demand" which based on the installed fuse capacities (between 20 and 150 kVA) limiting the maximum demands each consumer in this group can place on the network.

Group 3 ICP's have fixed charges based on TOU meter data and are expressed as:

(i) "dollars per AMD" (AMD=anytime maximum demand) and

(ii) "dollars per RCPD demand" The winter demand is the consumer's average demand measured coincident against the top 12 regional half hour coincident peak demands (RCPD) measured on the Upper South Island zone of the grid.

5.4.4 Variable/Consumption based Tariffs

Variable line tariffs are expressed as "cents per kWh" and apply to all consumer groups, except Group 6. The cents per kWh charges vary across differing tariff types, depending on the time of use profile where known or the level and type of load interruptability /restrictions the consumer commits to in advance.

5.4.5 Revenue Adequacy

The distribution revenue requirement for each group may exceed what that group is forecast to pay. For some groups, full recovery is unobtainable if rate shock is to be avoided or if NTL wants to avoid breaching either Government policy constraints or the Commerce Commission's regulatory default price pathway. This is particularly notable on network segments and in customer groups where connection density is low and where load factor is poor.

NTL does not make up under-recovery of distribution revenue from one particular customer group by over recovery from any of the other groups. All Groups recover their cash operating costs and depreciation and make some contribution to WACC. As a result there are no significant cross subsidies between customer Groups.

5.5 Distribution Prices - Group 1

Group 1 distribution revenue requirement is split between that part to be recovered by a fixed charge, and that part to be recovered by a variable charge.

The total annual fixed charge for all Group 1 ICP’s is set at $55pa. or 15 cents/day (the Government mandated low fixed charge). The distribution component of this fixed charge is $43.25pa. and is recovered from all consumers (ICPs) irrespective of geographical area or whether use is business or residential. This approach automatically establishes the proportion of revenue recoverable from fixed charges and NTL has adopted this position to:

- meet Government low user regulatory requirements
- avoid unwarranted discrimination between small business and small residential consumers
- minimise the additional transaction, administration and enforcement costs NTL and all electricity retailers face if a separate but optional low user tariff was offered only to qualifying domestic consumers.

The fixed charge recovers only 10% of the distribution revenue to be raised from Group 1. The total variable charge recovers the residual 90% of revenue from Group 1.

Variable tariff rates are determined by dividing the total variable charge by number of units consumed by Group 1 and applying a set of relative weightings between the tariff types on offer. The relative weights are in part driven by legacy issues but also reflect the relative costs of providing network services at "peak" versus "off peak" times and the benefits to the network of having interruptible loads. The weightings provide a signal for consumers to

- shift consumption "off peak" to night periods and
- permit components of their supply to be interrupted by NTL load control devices.

To provide a material difference between variable tariff rates, controlled and night rates are generally set to be less than half the standard anytime rate. Box 1 sets out the calculations that underpin the derivation of tariffs applicable to Group 1.

Box 1: Derivation of Group 1 prices

Load Group 1 : 2016-17 Budget Data
Distribution revenue budgeted 2016-17 = $14,272,000
Number of G1 ICPs (forecast) = 35,189

Total to be recoverable by fixed charges
Fixed charge per ICP per annum = $43.25 pa. or 11.85 cents /day
Total Group 1 fixed charges per annum= 35,189*$43.25
= $1,522,000

Total Group 1 Variable Charge: = $14,272,000 - $1,522,000
= $12,750,000

Prices	Allocated Weightings	Group 1 Budgeted Units
A - Anytime	100%	173.8 GWh
B - Day	110%	1.6 GWh
C - Controlled Water	46%	61.5 GWh
D - Night	33%	4.6 GWh

Line Charge Tariff A = $12,750,000 / (173.8*1.0 +1.6* 1.10+61.5 * 0.46+4.6*0.33)

	= 6.2 cents per kWh of A metered consumption
Line Charge Tariff B	= $0.062 * 1.10
	= 6.8 cents per kWh of B metered consumption
Line Charge Tariff C	= $0.062 * 0.46
	= 2.9 cents per kWh of C metered consumption
Line Charge Tariff D	= $0.062 * 0.33
	= 2.0 cents per kWh of D metered consumption

Note: Differences between the workings above and the disclosed tariffs are due to rounding

5.6 Distribution Prices - Group 2

Group 2 distribution revenue requirement is split between that to be recovered by a fixed capacity charge, and that part to be recovered variable charges.

Each ICP in Group 2 has an Anytime Maximum Demand (AMD between 20 and 150 kVA) based on installed supply fuse sizes.

Group 2 capacity charge revenue is targeted around 25% of the Group 2 revenue requirements, which is over twice the Group 1 level. This ensures fixed demand charges step up materially for consumers wishing to :

- Shift demand levels between Group 1 and Group 2
- upgrade installed fuse size within the kVA bands on offer within in Group 2.

Consumers are provided with a reasonable signal to minimise their peak capacity demands and to use scarce network capacity efficiently.

The total fixed charge revenue is divided by the sum of Group 2 AMDs to give a tariff expressed in dollars per kVA per annum. This rate is the same for all consumers within the group with no account being taken of geographical location.

The dollar per kVA tariff is multiplied by the individual ICP's AMD (derived from installed fuse size), to give a "demand charge" per year. This is divided by 365 and is billed on a cents per kVA per day basis.

The total variable charge recovers the residual revenue of the Group 2 revenue requirement using variable common tariff rates as shown above for Group 1.

Box 2 sets out the calculations used to determine Group 2 tariffs from the required revenue.

Box 2: Derivation of Group 2 prices

Load Group 2 data from 2016-17 Budget Data:

Consumer	Capacity (kVA)
x	40
y	70
z	110
…	…
Total Group 2	122,592 kVA

Group 2 Budgeted Revenue 2016-17		$6,899,000
Total Capacity Charge ~ 24%		$1,647,000
Total Variable Charge ~76%	$5,252,000	

Capacity Tariff	=	\$1,647,000 / 122,592
	=	\$13.43 per kVA pa or 3.68cents/kVA/day
Consumer "x" Capacity Charge/day	=	(13.43 * 40) / 365
	=	\$1.47 per day
Group 2 Variable Tariffs		
Total \$ to be recovered from variable charges in Group 2		
	=	\$6,899,000 – \$1,647,000
	=	\$5,252,000

Tariffs G2	Allocated Weightings	G2 Budgeted Units
A - Anytime	100%	65.8 GWh
B - Day	110%	17.5 GWh
C - Controlled Water	46%	3.8 GWh
D - Night	33%	7.5 GWh

Line Charge Tariff A	= \$5,252,000 / (64.5*1.0 +17.6* 1.10+3.8 * 0.46+7.8*0.33)
	= 5.9 cents per kWh of A metered consumption
Line Charge Tariff B	= \$0.059 * 1.10
	= 6.5 cents per kWh of B metered consumption
Line Charge Tariff C	= \$0.059 * 0.46
	= 2.7 cents per kWh of C metered consumption
Line Charge Tariff D	= \$0.059 * 0.33
	= 1.9 cents per kWh of D metered consumption

Note: Differences between the workings above and the disclosed tariffs are due to rounding

5.6.1 Group 2 Low User Pricing (2LFC)

Because there are a number of domestic customers in Group 2, regulation requires NTL to offer a compliant low fixed charge tariff option referenced against the standard pricing option outlined above. NTL provides a Group 2 low fixed charge tariff options with a 15 cent / day fixed charge and variable kWh rates adjusted upwards so that at 8,000kWh consumption per annum the line charges are equal to those payable on the standard tariff. The low user option is cheaper than the standard tariff for the very small number of Group 2 domestic consumers who use less than 8,000 kWh per annum but is poorly reflective of network supply costs.

5.6.2 High Load Factor Pricing (HLFC)

From 1 April 2012 NTL offered a pricing option suitable for mass market customers with high load factors. The tariff was introduced to offset one of the consequences of the variable (kWh) component of NTL standard mass market tariffs being higher than desirable. This situation has come about by NTL adopting the 15 cents per day low user fixed charge for all Group 1 consumers in order to achieve the fairest, simplest and most cost effective means of complying with the low user regulations. The consequential loss of fixed revenue has been made good through higher variable tariff rates. As a result high load factor consumers have ended up paying disproportionately high line charges per kVA of fuse capacity supplied.

The HLF tariff option, with higher capacity charges and considerably lower variable kWh rates, moderates the effect load factor has on line charges and constrains the cost per kVA supply charge. The HLF pricing is beneficial to mass market customers with load factors in excess of

about 25%; which is about 7% of Group 1&2 consumers. The HLF tariff also provides a smoother transition for these consumers where they move up to Group 3 pricing. NTL identifies those ICP's that would benefit from this tariff option and directly communicates with these consumers to ensure they are aware of this option.

5.7 Distribution Prices - Group 3

Group 3 distribution revenue requirement is split between that part recoverable by a capacity charge and that recoverable through peak demand and TOU consumption charges. Group 3 customers are primarily larger, high load factor business consumers and so the capacity based charges for this group are set to recover approximately 50% of required revenue. This provides strong signals to minimise anytime and winter peak demand levels (when combined with transmission component) and rewards good load factor much more than is the case in Groups 1&2 .

Each Group 3 consumer's AMD and RCPD demands are obtained from TOU data supplied by retailers:

- A Group 3 customer's RCPD quantity is the average of the consumers kW load coincident with Transpower's 12 peak loads on USI grid for the year ending 31st August in the previous year.
- A Group 3 customer's AMD is that consumers highest half hourly kVA at any time, in any month, during the year.

The total fixed charge revenue is divided by the sum of the AMDs and the RCPDs after establishing the relative weighting between the anytime and winter demand charges. The weighting is heavily biased towards the AMD charge because the RCPD is primarily used as a mechanism for directly passing through Transpower's Interconnection charges. This gives a dollar per AMD kVA and a dollar per RCPD kW as distribution tariffs .

The dollar per AMD (RCPD) tariff is multiplied by the ICP's AMD (RCPD), to give the ICP's anytime (RCPD) demand charge per year. Each annual demand charge is then divided by 365 and billed on a daily basis.

The total variable charge recovers the residual required distribution revenue not met by capacity /demand charges. The tariff rates are determined by dividing VC3 by the number of units consumed by load Group 3, and a relative weighting is established between the tariffs for summer day, summer night, winter day and winter night. This weighting process uses a similar rationale outlined for Group 1&2. Night rates and Summer Day rates are heavily discounted in comparison to Winter Day rates reflecting the off-peak use of the network during these time periods.

Box 3 shows the working used to determine Group 3 tariffs.

Box 3: Group 3 pricing calculations

Load Group 3: 2016-17 Budget Data:

Consumer	AMD	RCPD
x	225	100
y	194	120
…	…	…

Group Total	48,023	21,721		
Total Group 3 Dist. Revenue		$4,738,000		
Total Demand Based Revenue		$2,385,000		
Total Consumption Charge Revenue		$2,340,000		
AMD tariff % of demand charge		90%		
AMD Tariff			=	($2,385,000 * 0.90)/39,528
			=	$44.70 per kVA pa. or 12.2 cents/kVA/day
WMD Tariff			=	($2,385,000*0.1)/21,721
			=	$10.98 per kW pa. or 3.0 cents/kW /day
(The consumption charge per tariff is calculated in the same manner as for Group 1&2)				

Note: Differences between the workings above and the disclosed tariffs are due to rounding

5.8 Distribution Prices - Group 6.

There are only two consumers in Group 6 and both have sought direct service and billing arrangements with NTL rather than choosing to operate through normal interposed arrangements with electricity retailers. While their distribution pricing is individually assessed and direct billed by NTL their distribution revenue requirements are determined in a manner consistent with the other consumer Groups. Both Group 6 consumers have chosen to operate with NTL without formal written distribution supply contracts however NTL applies its standard terms of service and distribution code requirements to these consumers.

These consumers are large enough, and few enough, to warrant individual calculation of line charges based on the RAB values and direct costs associated with the dedicated or semi-dedicated assets used in their supply. General overheads are allocated using management estimates.

The methodology for allocating distribution costs, RAB values and determining the distribution revenue requirement for these consumers was described above. It is essentially the same and is consistent with the approach used for other customer groups but the resulting Group 6 revenue requirement is billed differently.

The Group 6 annual distribution revenue requirement is simply billed in fixed monthly amounts. It is essentially a fixed distribution asset rental regardless of changes in annual consumption or demand. The relative amounts billed to each Group 6 consumer are determined by the RAB asset values for the dedicated and semi dedicated assets used by each consumer.

5.9 Distribution Prices – Large embedded generator

The distribution charges applicable to the large embedded generator were set contractually based on the 66kV line asset values, maintenance and operational costs as per Transpower's 2014/2015 charge sheets. The proportion of the 66kV costs allocated to the large embedded generator was set with reference to the cost allocations previously used by Transpower.

6 PRICING FOR TRANSMISSION SERVICES

The grid owner Transpower charges NTL for use of the transmission grid. NTL recovers transmission costs by allocating them to consumer groups and recovering them through the transmission price component within line pricing.

6.1 NTL's Transmission Revenue Requirement

Transpower's transmission charges levied on NTL are relatively fixed and unavoidable. Transmission charges are billed by GXP and include the following components:

- Connection charges
- Interconnection charges
- New investment charges
- Loss and constraint rental rebate credits

NTL's Transmission Revenue Requirement is the sum of the cost listed above.

6.2 Allocation of Transmission Costs to Load Groups

Connection costs and new investment charges are levied at each Transpower grid exit point (GXP) for highly dedicated assets used to connect NTL to the grid. Connection costs are allocated to load groups on the basis of each group's (CMD) demand contribution coincident with the AMD of that GXP.

Forecast loss rental rebates are allocated to Groups 1, 2 & 3 on the basis of forecast consumption levels for each Group and are netted off total transmission costs to be recovered from each group.

Interconnection charges are allocated to Groups based on each Group's demand level measured coincident with Transpower's Upper South Island 12 peak chargeable RCPD half hours recorded over the winter of the previous year.

The connection, new investment and interconnection costs allocated to each group at each GXP are summed to obtain the gross transmission costs (revenue) to be recovered from that group.

With regard to the large embedded generator, connection costs are allocated using the same allocations previously utilised by Transpower.

6.3 Derivation of Transmission Tariffs

NTL recovers transmission costs from load Groups via a separate transmission pricing schedule incorporated within overall line pricing as follows:

(a) Consumers are classified into the same load groups as used for distribution pricing (see Section 5.2).

(b) Transmission costs for Group 6, Bulk Supply and Large Generator connections are recovered on a direct pass through basis (see Section 6.6).

(c) The remaining transmission costs, after Group 6, Bulk Supply and Large Generation pass through, are recovered from Group's 1-3 via NTL's transmission pricing schedule.

(d) Metering technology does not enable transmission costs to be passed directly through to mass market consumers in a manner that fully reflects the Transmission Pricing

Methodology. NTL therefore must rebundle transmission costs and recover them using the available billing metrics of kWh consumption, fuse capacity and fixed daily charges.

(e) Groups 1-3 transmission charges are recovered on a “fixed” and “variable” basis using similar rationale to that used in distribution pricing.

(f) To the extent possible within regulatory pricing constraints, NTL attempts to recover Transpower’s connection and new investment costs attributable to Groups 1 & 2 via fixed daily or capacity based charges and the interconnection cost attributable through variable (kWh) charges. However the regulated low fixed charge applied across all of Group 1 means a significant portion of connection costs for Group 1 must be recovered through variable tariff rates.

(g) Group 1 fixed charge is expressed as a "cents per day" charge.

(h) Group 2 fixed charge is expressed as “dollars per anytime maximum capacity” (AMD), measured in kVA and based on customer fuse size. The Group 2 capacity charge for transmission recovers the transmission connection and new investment costs attributable to Group 2. Interconnection costs attributable to Group 2 are recovered using variable (kWh) based charges.

(i) Group 3 fixed capacity charges are based on TOU meter data and are expressed as:

- "dollars per kW of RCPD” This RCPD component directly passes through Transpower’s Interconnection charges attributable to Group 3 consumers
- “dollars per kVA” of AMD, the AMD component recovers grid connection costs attributable to Group 3.

No variable (kWh) transmission tariffs are used to recover any transmission costs attributable to Group 3 consumers.

(j) Groups 1&2 variable Transpower tariffs are expressed as "cents per unit (kWh)" and they vary depending on the time of use profile or the level and type of load interuptability / restrictions the consumer commits to in advance.

6.4 Transmission Prices – Groups 1 – 3 Fixed and Capacity

6.4.1 Group 1

The total transmission cost attributable to Group 1 is split between that part to be recovered by a fixed charge and that part to be recovered by a variable charge.

The total fixed charge is divided by the number of ICPs in Group 1 to give the annual Group 1 charge per ICP but due to the limitations of the regulated low user fixed charge, attributable connection and new investment charges will be under recovered and so increment the level of Group1 variable transmission tariffs. The annual fixed charge for transmission is billed on a daily basis (annual charge per ICP / 365)

6.4.2 Group 2

The total transmission cost attributable to Group 2 is split between that part relating to connection and new investment charges to be recovered by a fixed charge, and that part to be recovered by a variable charge for the Interconnection charges attributable to Group 2.

Each ICP within Group 2 has an Anytime Maximum Demand (AMD) based on connection fuse size as described in Section 5.6 above.

The total fixed charge is divided by the sum of all individual AMDs within Group 2. This gives a dollar tariff per kVA of AMD per annum.

The dollar per kVA tariff is multiplied by the ICP's AMD, to give a "demand charge" per year. This is divided by 365 and billed on a daily basis.

6.4.3 Group 3

The total transmission cost allocated to Group 3 is recovered by fixed charges.

The connection and new investment component attributable to Group 3 is divided by Group 3's total AMD to yield a $/kVA rate. This rate is then applied to each individual consumers' AMD to determine their annual charge which is divided by 12 and billed monthly.

The Interconnection charges attributable to Group 3 are recovered based on individual customers demands measured coincident with the USI RCPD demand periods recorded over the previous year (RCPD).

The total amount recoverable by the RCPD charge, is divided by the total RCPD kWs for the Group. This gives a dollar tariff per kW of RCPD. The dollar per RCPD tariff is then multiplied by each ICP's metered RCPD kW to give the ICP's annual charge and is divided by 12 and billed monthly.

6.5 Transmission Prices - Groups 1-3 consumption (kWh)

Group 1&2 kWh charge amounts are recovered in a manner similar to G1&2 distribution charges.

Each kWh distribution tariff option for Groups 1&2 is classified as either a "peak" or an "off peak" tariff. Off peak time is for night only consumption (occurring between 2300 and 0700) or ripple controlled consumption which is virtually certain not to contribute to NTL's overall RCPD demand levels. Those in the peak time classification, are, by default, the remainder of the tariffs (Anytime or Day tariffs) and where consumption is not interruptible by NTL load control equipment and is consequently likely to contribute to NTL's chargeable RCPD quantities.

A relative weighting is applied to differentiate peak and non-peak kWh transmission tariffs in Groups 1&2. The weightings reflects the much higher likelihood of consumption / load in "peak" tariff categories contributing to USI RCPD demand levels and thus NTL chargeable interconnection quantities.

The total amount to recover by kWh transmission prices is then divided by total kWh consumption of Groups 1 or Group 2 respectively, and the relative weighting between the peak and off peak tariff is applied to determine the peak and off peak rates.

The kWh transmission prices are higher in Group1 than in Group 2 because the fixed charges in Group 1 do not fully recover connection and new investment costs attributable to that Group and the shortfall is made up within Group 1 variable rates. Connection and new investment costs attributable to Group 2 are fully recovered through the transmission component of the capacity based charges.

No kWh tariffs are used in Group 3 pricing to recover transmission costs.

6.6 Transmission Prices - Group 6, Bulk Supply and Large Generators

These consumers are large enough and few enough to have their Transpower charges individually calculated. The charges are by agreement determined on a cost reflective or "look through" basis so as to mirror the underlying Transpower charging methodology

Connection and new investment charges are allocated to the two Group 6 and the single Bulk supply customer in proportion to their average demands measured co-incident with the Stoke GXP's top 12 annual half hour AMD's for the prior year and are billed as a monthly fixed amount.

Interconnection charges are passed through directly on Group consumer demands measured coincident (after grossed up for distribution network losses between the customer TOU meter and the GXP TOU meter) with the relevant Upper South Island RCPD top 12 half hourly chargeable demands.

Any Common Quality Service Charges or Loss Rental Rebates are passed directly through to Group 6 and bulk supply consumers each month on the same basis as they are credited or charged to NTL by Transpower.

The Large Generator is allocated its share of the STK066 connection assets located at the Stoke substation.

The transmission charges described above are passed through to the two Group 6, one Bulk Supply and one large generator customer under letters of agreement or contracts in a transparent, cost reflective manner. All demand data and Transpower cost data for Stoke GXP used to determine annual transmission charges is supplied to these consumers each year.

7 DISTRIBUTED GENERATION

NTL has 1 large and 4 small hydro generators connected to and embedded within its network. It also has around 300 roof top solar generation plants connected and injecting into the network. Pricing for the large generator has been discussed in previous sections.

NTL uses regulated terms as a default contract with the small roof top solar plants but has more formal connection agreements with the 5 hydro plants. The regulated terms for small plants are taken from Schedule 6.2 "Regulated Terms for Connection of Distributed Generation" in Part 6 of the Electricity Industry Participation Code 2010 administered by the Electricity Authority.

NTL expects new generators to pay for their costs of connection to the existing network in the same manner any new off take connections must pay for their own dedicated costs of connection. To date for the generation plant connected to the network, all connection costs have been borne by the connecting parties and no upper network reinforcement has been necessary.

Where import and export can occur at the ICP NTL requires separate metering for both imported and exported kWh volumes.

To maintain competitive neutrality with other larger remote generators NTL:

- does not currently charge small scale local generators for injections exported onto and across the network.
- does not credit back any variable line charges on the energy exported into the network
- charges consumers who both import and export electricity from the same ICP the normal scheduled fixed / capacity charges applicable to the ICP plus standard variable tariffs on their separately metered import consumption
- as small scale roof top solar generation plants proliferate across the network NTL is experiencing:
    - additional time and costs in managing the safety aspects of both planned and unplanned outages.
    - Unavoidable increments to SAIDI and SAIFI times for planned and unplanned outages
    - No reduction in the critical winter evening peak loads that ultimately drive most NTL network investment
    - Some loss of variable tariff revenue as behind the meter consumption is offset by own generation
    - Risks around voltage stability in the lower network where the proliferation of solar DG plants is concentrated within neighbourhoods

Currently the "import only" ICP's are disproportionately bearing virtually all consequences associated with these incremental costs. Ultimately as these costs become more material NTL will have to adopt a stronger "beneficiaries/ exacerbates pays" element within its pricing. It is expected this will involve:

- adoption of higher levels of mass market fixed, capacity or demand based charges combined with a reduction in kWh tariff rates, where this possible
- time of use based pricing when metering technology permits
- introduction of a kWh tariff applied against export energy injected into the network

Where it can be demonstrated that new generation plant enables NTL to avoid distribution or transmission costs NTL recognises this with agreed payments to the generators.

Where time of use meters are installed at DG sites NTL passes through agreed avoided transmission Interconnection charges attributable to the embedded generator. Under the current transmission pricing methodology this is based on the generators half hourly injected kW measured coincident with the 12 peak RCPD half hourly demand periods annually measured for the Upper South Island. NTL passes through the agreed value of the avoided interconnection charges provided NTL can classify these payments as a Recoverable costs in its DPP price pathway. The avoided cost payments are determined as an annual sum and are paid monthly in the same manner TPNZ would bill NTL.

NTL has a relatively strong network in most areas and there have been no avoided distribution costs identified with respect of any new embedded generator connection to the network.

8 DISTRIBUTION PRICING PRINCIPLES & INFORMATION DISCLOSURE GUIDELINES

The Electricity Authority published a document "Guidelines for Distribution Pricing Principles and Information Disclosure" dated February 2010. This section evaluates the general compliance of NTL's Pricing Methodology and Policy for Connection of New Loads with these Guidelines. It also evaluates compliance with the Information Disclosure Guidelines.

8.1 Compliance with the Pricing Principles

In what follows:

- each Pricing Principle in the Guidelines is identified and
- NTL's general compliance the principle is reviewed

Pricing Principles (a) **Prices are to signal the economic costs of service provision, by:**
(i) being subsidy free (equal to or greater than incremental costs, and less than or equal to standalone costs), except where subsidies arise from compliance with legislation and/or other regulation;
The subsidy free test is a theoretical notion which at its limit requires a separate test for each of NTL's ICPs. To accurately estimate both incremental costs and standalone costs for particular customers or groups of customers is difficult and resource intensive and so the matter is addressed in general terms below. As a general principle if line pricing is cost reflective and costs are below new entrant levels the subsidy free test will be met. Allocation of consumers and costs to load groups and the development of prices for those load groups necessarily involves averaging and deployment of a number of assumptions. The resulting pricing is at best reasonably cost-reflective for broad groups of consumers. However the subsidy free range for line services for mass market consumers is also likely to be broad because incremental costs for the additional consumer/kVA/kWh are low while their standalone costs of supply are very high. This broad range means the cost reflective pricing methodology described in this document will generally lead to pricing within the subsidy free range. <u>Standalone Test</u> Distribution networks are natural monopolies and by definition deliver significant and long-term economies of scale to an extent that tests for standalone costs of alternative lines supply (overbuild) against existing cost reflective prices for mass market consumers should be largely redundant. NTL line pricing for Group 1 & 2 consumers is materially lower than the standalone

economic costs associated with alternative lines supply. This contention is supported by the fact that:

- NTL pricing methodology is cost reflective by Load Group
- NTL earns less than the regulator's WACC on the RAB value of its systems fixed assets
- TPNZ directly charges EDBs for their connection assets at GXP's. There are very strong economies of scale with respect to grid connection.
- Hence new overbuild costs combined with NTL's line business economies of scale means any replication of NTL distribution assets would be uneconomic when assessed against NTL' current mass market line charges derived from ODV based costs and highly shared TPNZ connection costs, either for individual consumers or for larger groups of consumers.

An alternative standalone test for small and medium sized consumers is to compare the cost of line supply against the costs of alternative standalone energy supply using on site micro generation plant. At the present time the cost of standalone reliance on micro generation remains higher than industry average and incremental supply costs although this test is more about cost of delivered energy than a disaggregated test focused just on the transport component of electricity costs. With consumers primarily interested only in the overall delivered cost of energy, the standalone subsidy free test for line charges is problematic given the need to split out line and energy costs.

Standalone cost tests have more relevance for the small number of larger consumers at specific locations on NTL's network. NTL's pricing methodology for Group 3&6 consumers is cost reflective and uses RAB based economic costs attributable to these customers. Additionally these consumers share in the economies of scale arising from high levels of sharing of:

- grid exit point costs
- upper network distribution assets
- indirect distribution costs.

Alternative supply via overbuild to these consumers would require economic costs to reflect full asset replacement costs (RCs) plus the loss of key scale economies. These standalone costs will therefore be well in excess of NTL's current line charges which is not supportive of an overbuild business case.

NTL has previously commissioned bypass costings for major customer sites to identify standalone costs and to assess the reasonableness of existing line charge levels. No adjustment to line pricing for major customers resulted.

<u>Incremental Cost Test</u>

Incremental cost is the additional cost associated with supplying an additional unit of service.

For distribution businesses the additional unit of service could be the:

- connection of an additional consumer
- supply of an additional kVA of capacity or
- transportation of an additional unit (kWh) of electricity.
- Delivering an increment in security or reliability

Generally incremental costs for extra kVA, kWh or connections are very low where the network has spare capacity but at some point new investment will be required causing a step change in costs to occur. It is difficult to assign or attribute the step changes in core network investment costs to specific additional units of service unless the additional load (service) is highly customer specific and is large relative to the network segment supporting it.

Most of the company's revenue is derived either from kVA charges (either from TOU metering or connection fuse size) or peak time kWh tariffs. Incremental network costs mostly arise from increases of load (kVA) at peak times. Therefore NTL pricing focus on capacity and peak tariff rates tends to align incremental revenue with incremental cost.

At a connection level NTL's connection policy requires developers and consumers to fund the incremental costs of any network extension necessary to support new connections and NTL is primarily left with funding new transformer capacity and any augmentation of core network capacity. Annual line charges are normally sufficient to service NTL's incremental costs for new connections plus provide a contribution to service and reinforce the core network.

NTL's connection policy also seeks network development levies based on distance and kVA for new loads in uneconomic areas of the network. This helps shore up the shortfall in incremental revenue in areas where incremental costs tend to be highest. The policy also enables NTL to reserve the right to seek capital contributions from any new load that is large relative to the capacity of the network segment it will rely on. This gives NTL the opportunity to undertake an economic assessment to ensure incremental costs are properly supported by expected future line charge revenues from the large new load. Where there is a shortfall NTL may seek a capital contribution to support the incremental costs.

Regulatory requirements to offer a low user tariff option to all domestic consumers and to maintain urban and rural line tariffs at similar levels tend to compromise incremental cost recovery and create subsidisation of some loads. Network costs for domestic customers do not vary materially with consumption (kWh) levels but the low fixed charge tariff requirements comprises revenue earning ability from low users relative to their incremental costs of supply. This is a material issue as 60% of NTL's domestic customers use less than < 8000 kWh pa. Similarly incremental costs in rural segments of the network tend to be considerably higher than in more dense urban areas but restrictions on the level differentiation between rural and urban tariffs leads to under recovery of incremental costs in these higher cost geographical segments.

These regulatory requirements tend to restrict line revenue available from one subgroup of consumers down to or below their incremental costs of supply while at the same time

raising the revenue drawn from another subgroup of consumers up towards their standalone costs of supply; consequently economic efficiency is compromised.
(ii) having regard, to the extent practicable, to the level of available service capacity; and
NTL Group 2&3 line pricing features kW and kVA pricing components directly related to the capacity demands consumers in these groups make on the distribution network and the transmission grid. NTL's service level (kVA) signals are moderate for Group 2 consumers but are strong for Group 3 consumers. Group 6 pricing reflects service levels demanded via charges based on the level of dedicated and semi dedicated distribution assets NTL commits to the supply of these consumers. Similarly within both Groups 3 & 6, Transpower's Interconnection Charge (a grid service capacity charge) is reflected directly through to each consumer on the basis of their capacity demands coincident with the grid's USI regional peak demand (RCPD). Where any consumer uses available network and grid capacity inefficiently NTL reserves the right to apply a kVA based power factor correction charge on sites with non-compliant power factor (PF<0.95). In practice this has been applied to TOU metered sites to good effect with only 4 out of NTL top 140 sites incurring the power factor charge. As stated, NTL also applies a kVA per kilometre network development levy regime for new loads locating on high cost, uneconomic segments of the network. The levy recognises demands for service capacity both in terms of network distance (km) and capacity level (kVA). Group 1 capacity/service level signals are relatively muted however every Group 1 ICP is restricted to a maximum demand capacity of 15 kVA via connection point fuses . Under the low user regulations a tariff option must be made available to all domestic consumers with a fixed / capacity component of no more than 15 cents per day. NTL applies the low user rate across all Group 1 ICP's in order avoid excessive transaction costs. Consequently NTL Group 1 pricing is primarily kWh based and poorly reflects the available capacity service levels to these consumers. Low use/low load factor consumers under pay for their available service capacity while high use/high load factor consumers over pay for the same capacity. This inefficiency and cross subsidy is an inevitable consequence of the low user tariff regulations.
(iii) signalling, to the extent practicable, the impact of additional usage on future investment costs.
The term "additional usage" is undefined in the Guidelines but presumably relates to • additional connections to the network; or • additional kVA demands at connection points; or • additional kWh consumption across the network. Given a network's primary function is to provide connectivity and to deliver capacity (kVA) between points of injection and load, additional kVA is probably the most meaningful measure of additional usage for an electrical network. In terms of "additional usage" future investment is driven by the location of new loads and

their impact on the network segment at peak demand times. Developing pricing components that reflect potential future investment costs due to new loads with any precision requires kVA-based charges that have locational and timing components associated with them. Alternative tightly time bound (TOU) kWh based tariffs could also provide useful but less accurate signalling.

Within an ICP based pricing regime, the ability to provide signals for the impact additional usage has on future investment is problematic because:

- very few mass market consumers have time of use metering, or as yet in this region, smart metering. Consequently it is not possible to measure coincident maximum demands and create peak-time kVA-based charges or kWh-based charges that have a useful time components embedded within them.
- Secondly, low user regulations prevent useful kVA signals being delivered to the majority of domestic consumers (over 70% or 21,300 domestic customers qualify for the low user tariff on NTL's network).
- Thirdly, there has been a desire by consumers, retailers and NTL trustee owners to avoid differentiated pricing between time zones and also across geographical segments of the distribution network for mass market consumers serviced with traditional interval metering. There is also an aversion to high fixed / capacity/ demand based charges by many smaller consumers.

The alternative for mass market consumers is a set of relatively blunt pricing instruments focused on maximum demand measured by installed fuse sizes combined with peak time kWh tariffs. NTL uses both these tools in its mass market pricing but in terms of signalling the impact of incremental usage on future new investment is relatively blunt.

Group 3 & 6 consumers all have TOU metering installed and face winter demand charges directly reflective of their contribution to the peak demand levels on the Upper South Island grid and on the distribution network. To the extent that the Interconnection Charge is reflective of Transpower's future grid upgrade costs, it is a very strong and clear signal.

Group 3 consumers also face an anytime demand charge which in part reflects the current and future cost of delivering capacity on the distribution network. However while it signals consumers to minimise demands in general, which is appropriate for lower network assets, it does not specify any critical network times or locations which would be more appropriate to upper network assets.

The distribution component of Group 6 network charges are based on the dedicated and semi-dedicated assets used to service these consumers. Any "additional usage" beyond the capacity of the existing dedicated assets will result in additional investment and the costs will be directly reflected back through to these consumers.

NTL's new connection policy provides for a network development levy on any large new load wishing to connect to the distribution network. The levy reflects any potential shortfall between expected future revenues and the incremental costs caused by the new load. Additionally NTL has a standard network development levy for new loads locating in uneconomic zones of the network that is a reflection of future network reinforcement costs

in these areas. The volume component of the levy reflects the incremental kVA demanded and its distance from the network's injection points and the price component reflects expected future reinforcement costs; usually capacitor bank installation costs or 11kV to 22kV conversion costs.

An important caveat is necessary for this section is that consumers tend to see and react to delivered electricity pricing signals rather than the individual line and energy components. From 1 April 2016 NTL's mass market consumers' (Group1&2 or about 97% of NTL's ICPs) charges will account for:

- between 30%-35% of total delivered charges for most mass market consumers.
- between 35%-45% of delivered "peak" kWh rates
- between 25%-30% of delivered "off peak" kWh rates
- between 15%-20% of the fixed daily charges for Group 1 consumers

Consequently NTL can only have a muted impact on delivered prices and consumer behaviour; its network pricing is relatively invisible to most consumers.

Retailers may also rebundle and alter the price relativities between network peak and off peak tariff rates. Thus network signalling of extra usage does not necessarily get clearly translated through to consumers so far as kWh charges (which account for the bulk of mass market line revenue) are concerned.

(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.

This test of efficient pricing focuses on Ramsey concepts of loading any revenue shortfalls over incremental cost onto consumers, products and services where demand elasticities are lowest.

As stated above most consumers respond to the full delivered cost of electricity rather than the lines component separately. NTL's line charges typically make up 30-35% of most consumers power bills while the generation and retail component makes up the remaining 65-70%. Line pricing signals are heavily buried within retail prices and remain subject to rebundling and thus provide only very muted consumption signals. Sensitivity to choices concerning shortfall recovery is therefore also likely to be muted. Therefore the means used to spread and collect any under recovered incremental costs is only of modest importance especially given distribution charges tend to be a declining proportion of consumers' power bills.

Demand elasticity is largely a function of the availability of substitutes. In terms of electricity delivered through traditional centralised generation plant, power grids and distribution networks the alternatives that drive demand elasticity are primarily gas, coal, wood, distributed micro generation, solar water heating and energy efficiency substitutes.

For virtually all NTL consumers:

- Coal and gas (other than gas for cooking) are not particularly viable substitutes in this region and commodity prices plus ETS charges are likely to make them

less so in the future.

- Incremental use of wood or coal is increasingly being marginalised as a heat source by clean air regulations in NTL's major urban areas.
- Small scale distributed generation is generally not fully viable although a number of consumers choose to adopt these technologies out of interest and a desire for independence and "greenness" rather than as a primary reaction to electricity prices. However recent price trends in PV panels have considerably improved the economics of micro generation plant embedded "behind" the meter.
- Energy efficiency initiatives (insulation, better lighting & appliances etc) tend to present one off opportunities at discrete points of time for consumers to lower part of their consumption for the long term
- Solar water heating is now a reasonably viable option vis electrically heated water.

Other than for water heating and growth of solar generation substitution, most electrical consumption remains relatively inelastic in the short to medium term. NTL also needs to retain off peak, controlled, night and summer kWh tariff rates at substantial discounts to peak and uncontrolled rates for network and demand efficiency reasons.

Use of fixed capacity or daily charges probably provides best means of making good under recoveries as these cause minimal distortion to consumption patterns at the mass market level. However the low user fixed charge regulations limit what can be achieved with respect domestic customers and force loadings on variable tariffs . While "peak" variable tariff rates can also be used these tend to encourage the most substitution especially through solar generation installation and energy efficiency initiatives. Use of "off peak" and "controlled" rates for shortfall recoveries risks compromising network investment efficiency through encouraging less controllable and night loads.

(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;

Bypass may occur through alternative network assets (i.e. by overbuild of existing network) or by customers adopting alternative energy sources /substitutes.

Network pricing can address overbuild bypass incentives by ensuring network charges remain below the standalone economic costs for alternative lines supply for particular consumers or groups of consumers. This matter is addressed in (a)(1) above and NTL considers its network pricing and polices discourage inefficient bypass by an alternative lines service. NTL has historically reviewed bypass opportunities for major TOU customers but the businesses cases were not supported by NTL's line pricing. NTL is unaware of any consumers exercising overbuild bypass choices solely in response to line charge levels.

Bypass via consumers adopting alternative energy sources is more problematic. This type of bypass is incentivised by the delivered cost of energy rather than just the lines cost. NTL

has limited influence over the delivered cost of electricity and as noted above NTL's line charges typically make up only 30-35% of energy bills for most mass market consumers. Given this fact NTL is very limited in what it can do to discourage inefficient uptake of alternative energy sources as a means of bypassing the electricity system. That said increasing the amount of lines revenue obtained from fixed daily charges and anytime kVA based charges would help lower incentives for inefficient bypass of network assets via small /micro generation, especially solar generation, embedded " behind the meter." It would also reward and help the "best" network customers while challenging the most uneconomic.
(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
NTL considers that for mass market consumers (98 % of NTL 38,300 ICPs) the electrical network is a "general commons" and the notion of offering price quality/trade-offs for a specific mass market customer(s) is fundamentally flawed. Generally other than offering a choice of differing capacity levels and peak and off peak /controlled tariff options to mass market consumers, NTL is generally unable to offer other differentiated lines services to one consumer without at the same time providing it to all other adjacent consumers sharing the same network segments, whether they want, or are prepared to pay for the service, or not. However larger customers are more able to contract for different levels of service where they have high levels of asset dedication. NTL's Group 6 consumers have specific and dedicated network requirements and these requirements are reflected in the assets proved, the service terms and the pricing NTL has in place with these consumers. NTL has surveyed and consulted with Group 3&6 and larger Group 2 consumers concerning price quality/trade-offs in the past as part of the thresholds price control regime. These consultations now continue as part of the AMP process. The consultations generally show these consumers have primary concerns over changes in the *delivered* price of electricity rather than concerns about changes to service quality. Quality was mostly of second order interest or priority. NTL found it difficult to isolate consumers views down to those just centred on lines price and performance rather than those centred on the performance of the whole delivered energy package. NTL has also canvased electricity retailer views (as representatives of their customers) over line pricing and their primary concerns focus on simplicity and pass through risk rather than anything remotely concerned with price quality trade-offs. NTL, as a consumer trust owned EDB, must agree on its SCI each year with Trustees (who are elected by and represent consumers interests). The SCI considers company pricing, revenue and cost targets as well as quality and reliability targets. Performance is regularly reported against these targets to the Trust. The Trustees hold the power to appoint NTL Directors and be consulted over any major transactions proposed by the company. This structure puts in place a viable feedback loop to the company from consumers and stakeholders.

(iii) where network economics warrant, and to the extent practicable, encourage investment in transmission and distribution alternatives (e.g. distributed generation or demand response) and technology innovation.

NTL line pricing directly or indirectly encourages consideration of distribution and transmission alternatives and innovation in the following ways:

- NTL only charges new embedded generators for their incremental costs of connecting to the network. NTL passes through demonstrable savings in transmission interconnection charges generators deliver provided they are TOU metered. Where warranted, NTL will also consider passing through any avoided distribution costs directly attributable to new embedded generation plant.
- NTL pricing passes through Transpower Interconnection charges directly to Group 3 & 6 consumers, based on TOU data. They thereby gain full value from any means they may have of reducing or avoiding demand coincident with USI peak grid loads.
- NTL's Group 3 capacity based AMD pricing incentivises consumers to minimise their peak loads on the distribution network. Demand reduction such as on site power factor correction or any other means of limiting peak load is rewarded by way of materially lower (circa $59/kVA pa) network charges.
- NTL Group 3 pricing includes a power factor charge ($93/kVAr pa.) for consumer sites where power factor is non-compliant (worse than 0.95). This combined with AMD and RCPD capacity charges strongly incentivises consumers to install technology that enables scarce grid and distribution capacity to be used efficiently.
- NTL Group 2 pricing includes capacity charges based on installed fused sizes. This provides moderate incentives for consumers to minimise their ICP fusing requirements and to find ways of avoiding increasing peak demands on the network. It also acts as a disincentive for consumers to move up to Group 2 from Group 1,where fixed charges are artificially low.
- NTL pricing has, for all consumers, considerably higher kWh rates on tariffs chargeable on "peak" consumption than for "off peak" or "controlled" consumption. The "on peak" tariff rates are, in general, more than double the "off peak" and "controlled" rates so in theory consumers are incentivised to move consumption away from peak. However given NTL's line tariffs are mostly no more than 35% of the delivered power bill, these signals are substantially muted by energy retailers who tend to offer minimal, nil, or negative "off peak" incentives in the energy portion (the other 65%) of consumers power costs.
- NTL requires an upfront network development levy, reflecting both kVA and distance, for new loads seeking new capacity in uneconomic areas of the network. The development levy signal is stronger the larger the load and the further it is away from an NTL GXPs or zone substations. This progressively encourages all remote new loads to minimise their new capacity demands on segments of distribution network that are uneconomic to reinforce and to explore alternative and more efficient ways of supplying their new capacity requirements.

- Large new loads are subject to an economic test that assesses incremental cost against expected future revenue streams. Where there is a shortfall a network development levy can be sought. This incentivises minimisation of capacity use and consideration of alternatives.
- New connections/loads on NTL's distribution network are required to fund any new network extension assets (excluding transformers) necessary to connect their new ICP to the existing distribution network. This policy helps NTL avoid funding uneconomic and undesirable network extensions and incentivises new connections to consider the most economic means of getting power to their particular chosen localities.

(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.

Pricing transparency, stability and certainty is supported by NTL in the following ways:

- NTL makes commitments as to structure, stability and certainty for line pricing in its SCI with NT Trust
- NTL is legally bound by its UOSA with retailers to consult over changes in pricing methodology and to provide adequate notice of changes in prices and pricing methodology.
- NTL commitments to pricing stability and certainty in its UOSA with retailers.
- NTL commits to only change its distribution pricing once in any 12 month period however NTL reserves the right to alter transmission pricing whenever Transpower changes its charges to NTL.
- NTL undertook a major simplification of its line pricing in 2004 and has rolled forward this pricing in accord with its pricing methodology and pricing commitments since that date.
- The requirement to comply with the low user regulations and the pass through of changes to Transpower's pricing regime are the primary causes of rate shock for some consumers since 2004. The low user regulations were detrimental to high load factor consumers while changes to Transpower's charging methodology adversely impacted on all consumers; especially those in Groups 3 &6.
- NTL is a "controlled" line business under S54 of the Commerce Act and as such must adhere to the price control requirements of the Default Price Quality Regulation and the Starting Price Adjustment Process (Po) or seek a Customised Price Quality Price Pathway.
- NTL has operated at or below its regulatory price path cap since its introduction in 2003 and this has promoted rate stability and certainty for retailers, consumers and stakeholders. Consequently the distribution component of NTL's line charges have been falling or stable in real terms for at least 12 years.
- NTL has forgone its Po adjustment (+9%) at 1 April 2013 to promote certainty and stability and to avoid applying increases that would later have needed to be

reversed.

- NTL pricing largely avoids cross subsidisation between consumer load groups and consequently the company accepts under recovery of allowable revenue in load groups where there are higher numbers of uneconomic consumers.
- NTL annually makes available in the public domain (on its website or makes publicly available) its:
  - SCI (agreed with Trustee owners)
  - Annual Financial Statements (audited)
  - Pricing Methodology
  - Line prices split into distribution and transmission components
  - Non Standard supply contracts
  - Use of Systems Agreements
  - AMP (reviewed by regulator)
  - Default Price Path Compliance Statements (audited)
  - Information Disclosures (audited)
  - New connections and contributions policy

These documents directly or indirectly provide pricing and cost information and offer a high level of transparency to stakeholders.

(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.

The structure of NTL's current line pricing has evolved in consultation with retailers.

Line pricing is at ICP level and is simple to understand and apply while minimising transaction costs for retailers, consumers and NTL. All retailers are treated in an even handed manner under this pricing structure, which is a requirement in standard UOSA terms.

The Use of Systems line pricing is standard across, and applies equally to, all retailers:

- There is a single standard fixed daily charge for all Group 1 consumers. This fixed daily charge fully meets the low user tariff regulations so complexity and transaction costs are minimised.
- There is one standard kVA capacity charge rate applicable for all Group 2 consumers (covers about 2750 Group 2 ICP's) unless consumers opt of a low fixed charge tariff or a high load factor tariff. ICP details and their chargeable capacities are updated on the Registry and are directly available to all electricity retailers
- There are just 5 core variable (kWh) tariff rates applicable to consumers in each of Group 1 &2

- The regulated low user tariff has been applied across all Group 1 ICP's making line pricing decisions for around 92% of NTL ICP's very simple for retailers.
- The regulatory requirement to make available a low user charge for all domestic consumers more than doubles the number of tariff lines in the Group 2 tariff schedule despite only 25 domestic customers in this group taking up the option. The regulations increase complexity and transaction costs for both NTL & retailers.
- There is no tariff variation by regional/geographical area or by consumer type /use (i.e. by business, domestic, irrigation etc) for mass market consumers
- NTL's Group 3 line charges are relatively straight forward but rely heavily on TOU data. Group 3 TOU consumers are split in categories by size with 133 of the consumers being in the most numerous category. Each Group 3 consumer faces NTL's winter and an anytime peak capacity charge with the relevant annual chargeable demand quantities taken from TOU data. Consumption charges are TOU based and are split between day and night on a summer winter basis.
- At their request, Group 6 line charges are direct billed to customers rather than through retailers under UOSA's. Transmission costs are a direct pass through of TPNZ charges on a proportionate basis. Line charges are an annual rental amount, billed monthly without retailer involvement.

8.2 Compliance with Information Disclosure Guidelines

The Information Disclosure Guidelines and NTL's general compliance with them is discussed in the following table.

<u>Information Disclosure Guidelines</u>
(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.*
NTL's pricing methodology is extensively explained above, is published annually and is made available on the company's website. The underlying pricing methodology has had no material revisions for the 2016-17 year.
(b) The pricing methodology disclosed should demonstrate:
(i) how the methodology links to the pricing principles and any non-compliance;
The link between the pricing methodology and the Electricity Authority pricing principles has been explained in this document.
(ii) the rationale for consumer groupings and the method for determining the allocation of consumers to the consumer groupings;
Section 5.3 explains NTL's method of allocating consumers to load groups and this applies to both distribution and transmission pricing components.
(iii) quantification of key components of costs and revenues;
See Section 5 for a description of distribution costs and revenue components. See Section 6 for description of transmission costs and revenue components. See Appendix A for NTL data on cost and revenue components.
(iv) an explanation of the cost allocation methodology and the rationale for the allocation to each consumer grouping;

See Section 5.3 for description of the methodology for allocation of distribution costs to consumer Load Groups. See Section 6.2 for description of the methodology for the allocation of transmission costs to consumer Load Groups. See Appendix A for NTL's data showing costs allocated to Load Groups for 2015-16.
(v) an explanation of the derivation of the tariffs to be charged to each consumer group and the rationale for the tariff design; and
See Section 5 for description of distribution tariff components & derivation. See Sections 6 for description of transmission tariff components & derivation. See Appendix A for NTL tariff data for 2016-17.
(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.
Generally NTL has very few load constraints on its network so at this juncture there is limited value offering specific incentives schemes to curtail load. NTL's does not currently offer any formal arrangements to share any deferral of investment in distribution and transmission assets other than for embedded generators. However as noted in c(iii) above there are a number of useful indirect incentives within NTL's line pricing structure and contractual agreements that reward any customer behavior limiting peak demand or lowering NTL costs. • Distributed generators are directly rewarded via pass through agreed savings they cause with respect to NTL's Interconnection Charges. Any potential for deferral of distribution investment will be site and plant specific and so will be dealt with on a case by case basis. • Group 6 consumers obtain full benefit from any reduction in RCPD coincident demands with respect to Interconnection Charges directly passed through by NTL. • Group 3 AMD and RCPD demand charges automatically reward any load reductions at critical times, whatever their cause, on NTL's distribution network and the Upper South Island grid respectively. • Group 2 capacity charges provide moderate rewards and incentives for constraining consumer's peak loads. Lower investment in LV assets such as conductor, transformers and fusing is thereby encouraged. • Off peak & controlled kWh charges incentivise and reward mass market consumers for shifting load to off peak times or enabling their load to be interrupted. NTL's peak network and grid loads are about 10-12% lower than they would have otherwise been as a result of historical uptake of controlled tariff options and use of centralized load control plant.
(c) The pricing methodology should:
(i) employ industry standard terminology, where possible; and
NTL employs standard industry terminology throughout its pricing methodology.
(ii) where a change to the previous pricing methodology is implemented, describe the impact on consumer classes and the transition arrangements implemented to introduce the new methodology
NTL has not changed its pricing methodology for the pricing year commencing 1 April 2016. The distribution component of NTL's price has remained unchanged at the same pricing applicable from 1 April 2015 to 31 March 2016. Transmission charges have increased in order to pass through increases in Transpower's charges, however the methodology to translate those increases into pricing has remained unchanged. Year on year changes in the components of revenue and costs can be ascertained from comparative data in Appendix A

Appendix A: Cost allocation by load group

LOAD GROUP STATISTICS USED IN PRICING METHODOLOGY

For year commencing 1 April 2016

Customer Group	Number of ICP's	Coincident Maximum Demand (1)	Anytime Maximum Capacity	Winter Maximum RCPD	Consumption Peak	Consumption Off Peak	Total Consumption	RAB Value Allocated
	#	kW	kVA	kW	kWh	kWh	kWh	$'000m
Group 1	35,994	53,290	539,910	53,744	170,602,307	65,437,038	236,039,345	$ 82.36
Group 2	2,773	27,304	118,070	16,337	89,775,039	13,052,726	102,827,765	$ 46.36
Group 3	148	27,433	44,242	20,631	100,561,828	37,894,792	138,456,620	$ 27.04
Group 6	2	18,206	20,112	17,852	N/A	N/A	119,374,436	$ 3.27
Bulk supply	1	N/A	25,332	17,592	N/A	N/A	99,854,289	$ 4.09
Total	**38,918**	**126,233**	**747,666**	**126,156**			**696,552,455**	**$ 163.12**

Notes:

N/A Not used in pricing methodology
(1) Based on rolling average
(2) Group 3& 6 information taken from Time of Use metered data
(3) Group 1&2 kVA based on customer installed fuse capacity

SEPARATION OF ESTIMATED REVENUE AND COSTS COMPONENTS TO LOAD GROUPS

For the year commencing 1 April 2016

Customer Group	Transmission Costs	Direct NW Costs	Indirect NW Costs	Depreciation	Allowable PreTax Return on RAB	TRR Total Revenue Requirement	Targeted Budget Line Revenue	Over / (Under) Recovery Pre disct	Revaluations @ CPI = 0.4%	Over / (Under) Recovery vs TRR	Over / (Under) % Recovery vs TRR
	$	$	$	$	$	$	$	$			
Group 1	$ 5,887,337	$ 4,063,773	$ 1,945,280	$ 3,646,794	$ 7,413,511	**$ 22,956,694**	**$ 21,719,649**	**$ (1,237,045)**	**$ 329,432**	**$ (907,613)**	**(4)%**
Groups 2 & HLF	$ 1,913,566	$ 2,165,832	$ 425,403	$ 1,943,599	$ 4,409,765	**$ 10,858,165**	**$ 10,557,294**	**$ (300,871)**	**$ 185,439**	**$ (115,432)**	**(1)%**
Group 3	$ 2,327,008	$ 1,428,912	$ 468,791	$ 1,282,293	$ 2,625,068	**$ 8,132,072**	**$ 7,771,450**	**$ (360,622)**	**$ 108,178**	**$ (252,445)**	**(3)%**
Group 6	$ 2,080,739	$ 115,300	$ 51,583	$ 194,128	$ 333,592	**$ 2,775,342**	**$ 2,530,487**	**$ (244,855)**	**$ 13,067**	**$ (231,789)**	**(8)%**
Bulk supply and large generator	$ 2,405,567	$ 694,439	$ 44,000	$ 153,122	$ 418,002	**$ 3,715,130**	**$ 3,711,500**	**$ (3,629)**	**$ 16,373**	**$ 12,743**	**0%**
Total	**$ 14,614,217**	**$ 8,468,256**	**$ 2,935,057**	**$ 7,219,935**	**$ 15,199,939**	**$ 48,437,403**	**$ 46,290,381**	**$ (2,147,023)**	**$ 652,488**	**$ (1,494,535)**	

Note: For the purposes of protecting confidentiality of the underlying data the Bulk Supply and Large Generator categories have been aggregated

Appendix B: Network Tasman pricing effective from 1 April 2016

As required under Section 2.4.18 of the Electricity Information Disclosure Determination 2012.

Network Tasman Limited Pricing From 01 April 2016 to 31 March 2017

Price description		Connections with this price	Unit of measure	Distribution price 2016-17	Transmission price 2016-17	Total price 2016-17	Distribution price last year	Transmission price last year	Total price last year
General connections 15-150 kVA capacity									
Group 1 15kVA capacity									
Daily price	1	35,618	c/day	11.85	3.15	**15.00**	11.85	3.15	**15.00**
Anytime continuous	1ANY	34,705	c/kWh	6.17	3.04	**9.21**	6.17	2.98	**9.15**
Day (of day/night)	1DAY	323	c/kWh	6.78	3.36	**10.14**	6.78	3.29	**10.07**
Night	1NIT	4,010	c/kWh	2.04	1.03	**3.07**	2.04	1.01	**3.05**
Off peak controlled	1OPK	180	c/kWh	4.84	2.33	**7.17**	4.84	2.28	**7.12**
Controlled water	1WSR	27,002	c/kWh	2.87	1.38	**4.25**	2.87	1.35	**4.22**
Group 2 20-150 kVA									
Capacity (except domestic low users)	2	2,683	c/kVA/day	3.68	1.53	**5.21**	3.68	1.50	**5.18**
Anytime continuous	2ANY	2,233	c/kWh	5.87	2.24	**8.11**	5.87	2.20	**8.07**
Day (of day/night)	2DAY	461	c/kWh	6.45	2.49	**8.94**	6.45	2.44	**8.89**
Night	2NIT	585	c/kWh	1.94	0.75	**2.69**	1.94	0.74	**2.68**
Off peak controlled	2OPK	36	c/kWh	4.61	1.72	**6.33**	4.61	1.69	**6.30**
Controlled water	2WSR	731	c/kWh	2.72	1.03	**3.75**	2.72	1.01	**3.73**
Group 2 Domestic LFC, < 40kVA capacity									
Group 2 domestic low users < 40kVA	2LLFC	32	c/day	11.85	3.15	**15.00**	11.85	3.15	**15.00**
Anytime continuous	2LANY	27	c/kWh	8.81	3.36	**12.17**	8.81	3.30	**12.11**
Day (of day/night)	2LDAY	4	c/kWh	9.38	3.62	**13.00**	9.38	3.55	**12.93**
Night	2LNIT	9	c/kWh	4.86	1.89	**6.75**	4.86	1.86	**6.72**
Off peak controlled	2LOPK	0	c/kWh	7.57	2.82	**10.39**	7.57	2.77	**10.34**
Controlled water	2LWSR	15	c/kWh	5.67	2.14	**7.81**	5.67	2.10	**7.77**
Group 2 domestic LFC, ≥ 40kVA capacity									
Group 2 domestic low users ≥ 40kVA	2HLFC	1	c/day	11.85	3.15	**15.00**	11.85	3.15	**15.00**
Anytime continuous	2HANY	1	c/kWh	12.24	4.69	**16.93**	12.24	4.59	**16.83**
Day (of day/night)	2HDAY	0	c/kWh	12.81	4.95	**17.76**	12.81	4.84	**17.65**
Night	2HNIT	0	c/kWh	8.28	3.23	**11.51**	8.28	3.16	**11.44**
Off peak controlled	2HOPK	0	c/kWh	11.02	4.13	**15.15**	11.02	4.04	**15.06**
Controlled water	2HWSR	0	c/kWh	9.11	3.46	**12.57**	9.11	3.38	**12.49**
Group HLF (15 - 150kVA)									
Capacity price	HLF	53	c/kVA/day	31.24	8.78	**40.02**	31.24	8.61	**39.85**
Anytime continuous	HLFANY	37	c/kWh	1.67	0.61	**2.28**	1.67	0.60	**2.27**
Day (of day/night)	HLFDAY	22	c/kWh	1.81	0.67	**2.48**	1.81	0.66	**2.47**
Night	HLFNIT	23	c/kWh	0.52	0.19	**0.71**	0.52	0.19	**0.71**
Off peak controlled	HLFOPK	0	c/kWh	1.30	0.48	**1.78**	1.30	0.47	**1.77**
Controlled water	HLFWSR	9	c/kWh	0.75	0.28	**1.03**	0.75	0.27	**1.02**
Generation (eg solar export)	GENA	438	c/kWh	0.00	0.00	**0.00**	0.00	0.00	**0.00**
GROUP 3. TOU metered, ≥150 kVA									
Category 3.1									
Anytime kVA demand	AnyDem31	4	c/kVA/day	9.01	3.38	**12.39**	9.01	3.31	**12.32**
RCPD kW demand	WinDem	148	c/kW/day	3.19	30.77	**33.96**	3.19	30.17	**33.36**
Summer day	SD31	4	c/kWh	0.44	0.00	**0.44**	0.44	0.00	**0.44**
Summer night	SN31	4	c/kWh	0.24	0.00	**0.24**	0.24	0.00	**0.24**
Winter day	WD31	4	c/kWh	0.79	0.00	**0.79**	0.79	0.00	**0.79**
Winter night	WN31	4	c/kWh	0.24	0.00	**0.24**	0.24	0.00	**0.24**
Category 3.3									
Anytime kVA demand	AnyDem33	4	c/kVA/day	11.64	3.38	**15.02**	11.64	3.31	**14.95**
RCPD kW demand	WinDem	148	c/kW/day	3.19	30.77	**33.96**	3.19	30.17	**33.36**
Summer day	SD33	4	c/kWh	1.35	0.00	**1.35**	1.35	0.00	**1.35**
Summer night	SN33	4	c/kWh	0.71	0.00	**0.71**	0.71	0.00	**0.71**
Winter day	WD33	4	c/kWh	3.45	0.00	**3.45**	3.45	0.00	**3.45**
Winter night	WN33	4	c/kWh	0.71	0.00	**0.71**	0.71	0.00	**0.71**
Category 3.4									
Anytime kVA demand	AnyDem34	138	c/kVA/day	12.42	3.38	**15.80**	12.42	3.31	**15.73**
RCPD kW demand	WinDem	148	c/kW/day	3.19	30.77	**33.96**	3.19	30.17	**33.36**
Summer day	SD34	138	c/kWh	1.35	0.00	**1.35**	1.35	0.00	**1.35**
Summer night	SN34	138	c/kWh	0.71	0.00	**0.71**	0.71	0.00	**0.71**
Winter day	WD34	138	c/kWh	3.45	0.00	**3.45**	3.45	0.00	**3.45**
Winter night	WN34	138	c/kWh	0.71	0.00	**0.71**	0.71	0.00	**0.71**
Category 3.5									
Anytime kVA demand	AnyDem35	2	c/kVA/day	11.64	3.38	**15.02**	11.64	3.31	**14.95**
RCPD kW demand	WinDem	148	c/kW/day	3.19	30.77	**33.96**	3.19	30.17	**33.36**
Summer day	SD35	2	c/kWh	0.91	0.00	**0.91**	0.91	0.00	**0.91**
Summer night	SN35	2	c/kWh	0.57	0.00	**0.57**	0.57	0.00	**0.57**
Winter day	WD35	2	c/kWh	2.95	0.00	**2.95**	2.95	0.00	**2.95**
Winter night	WN35	2	c/kWh	0.57	0.00	**0.57**	0.57	0.00	**0.57**
Power factor charge (where applies)									
All group 3 categories	kVAr	3	c/kVAr/day	25.45	0.00	**25.45**	25.45	0.00	**25.45**
Large category fixed charge only[1]									
Cat 6.1	6.10	1	per annum	214,575	1,815,008	**2,029,583**	214,575	1,779,304	**1,993,879**
Cat 6.2	6.20	1	per annum	229,973	362,829	**592,802**	229,973	335,220	**565,193**
Cat CB		1	per annum	1,308,853	318,948	**1,627,801**	1,307,761	317,121	**1,624,882**
Group 0 (unmetered)									
Low capacity - electric fences, ph boxes etc	0UNM	87	c/day	35.00	18.00	**53.00**	35.00	18.00	**53.00**
Streetlight only connection	0S	25	c/day	0.00	0.00	**0.00**	0.00	0.00	**0.00**
Streetlight attached	0STL	150	c/W/day	0.079	0.038	**0.117**	0.079	0.037	**0.116**

Notes

Prices apply for all GXPs/Regions for each Group/Category

LFC = Low User Fixed Charge for less than 8,000 kWh consumption pa

Price Exclude GST

Discounts are based on a combination of kWh and a fixed amount. Contact NTL for details

Note1 Plus varying monthly ancilliary and LRR pass through charges

Appendix C: Proportion of Target Revenue collected through each pricing component

As required under Section 2.4.3 (8) of the Electricity Information Disclosure Determination 2012.

Price/Tariff Description	Code	No of ICPs	Revenue		Proportion of Total Revenue		
			Transmission	Distribution	Transmission	Distribution	Total
Group 0 (unmetered)							
Low capacity - Electric fences, Comms etc	0UNM	93	81,902	170,271	0.19%	0.39%	0.574%
Streetlight only connection	0S	26	0	0	0.00%	0.00%	0.000%
Streetlight attached	0STL	163	0	0	0.00%	0.00%	0.000%
Metered supplies, 15-150 kVA Capacity							
Group 1 15kVA capacity							
Daily Charge	1	35,618	413,841	1,556,830	0.94%	3.55%	4.489%
Anytime Continuous	1ANY	34,705	5,284,471	10,725,391	12.04%	24.43%	36.467%
Day (of Day/Night)	1DAY	323	54,904	110,788	0.13%	0.25%	0.377%
Night	1NIT	4,010	4,629	9,169	0.01%	0.02%	0.031%
Off Peak Controlled	1OPK	180	106,513	221,255	0.24%	0.50%	0.747%
Controlled Water	1WSR	27,002	848,114	1,763,832	1.93%	4.02%	5.949%
Group 2 20-150 kVA							
Capacity (Except domestic low users)	2	2,683	684,408	1,645,877	1.56%	3.75%	5.308%
Anytime Continuous	2ANY	2,233	1,471,869	3,858,518	3.35%	8.79%	12.141%
Day (of Day/Night)	2DAY	461	434,425	1,125,573	0.99%	2.56%	3.553%
Night	2NIT	585	1,577	3,891	0.00%	0.01%	0.012%
Off Peak Controlled	2OPK	36	129,167	346,199	0.29%	0.79%	1.083%
Controlled Water	2WSR	731	39,335	103,717	0.09%	0.24%	0.326%
Group 2 Domestic LFC, < 40kVA capacity							
Group 2 Domestic low users < 40kVA.	2LLFC	32	195	735	0.00%	0.00%	0.002%
Anytime Continuous	2LANY	27	2,900	6,038	0.01%	0.01%	0.020%
Day (of Day/Night)	2LDAY	4	417	827	0.00%	0.00%	0.003%
Night	2LNIT	9	141	554	0.00%	0.00%	0.002%
Off Peak Controlled	2LOPK	0	4	10	0.00%	0.00%	0.000%
Controlled Water	2LWSR	15	255	831	0.00%	0.00%	0.002%
Group 2 Domestic LFC, ≥ 40kVA capacity							
Group 2 Domestic low users ≥ 40kVA	2HLFC	1	11	43	0.00%	0.00%	0.000%
Anytime Continuous	2HANY	1	215	691	0.00%	0.00%	0.002%
Day (of Day/Night)	2HDAY	0	0	0	0.00%	0.00%	0.000%
Night	2HNIT	0	0	0	0.00%	0.00%	0.000%
Off Peak Controlled	2HOPK	0	0	0	0.00%	0.00%	0.000%
Controlled Water	2HWSR	0	0	0	0.00%	0.00%	0.000%
Group HLF (15 - 150kVA)							
Capacity Charge	HLF	53	100,307	356,901	0.23%	0.81%	1.041%
Anytime Continuous	HLFANY	37	25,904	70,916	0.06%	0.16%	0.221%
Day (of Day/Night)	HLFDAY	22	24,684	66,685	0.06%	0.15%	0.208%
Night	HLFNIT	23	0	0	0.00%	0.00%	0.000%
Off Peak Controlled	HLFOPK	0	7,070	19,147	0.02%	0.04%	0.060%
Controlled Water	HLFWSR	9	85	227	0.00%	0.00%	0.001%
Generation (all groups/categories)	GENA	438					
GROUP 3. TOU metered, ≥150 kVA							
Category 3.1							
Anytime Demand	AnyDem31	4	27,400	73,041	0.06%	0.17%	0.229%
RCPD Demand (incl all other G3 categories)	WinDem	148	2,439,496	252,908	5.56%	0.58%	6.133%
Summer Day	SD31	4	0	19,978	0.00%	0.05%	0.046%
Summer Night	SN31	4	0	4,596	0.00%	0.01%	0.010%
Winter Day	WD31	4	0	25,285	0.00%	0.06%	0.058%
Winter Night	WN31	4	0	3,226	0.00%	0.01%	0.007%
Category 3.3							
Anytime Demand	AnyDem33	4	15,125	52,088	0.03%	0.12%	0.153%
RCPD Demand	WinDem	148					
Summer Day	SD33	4	0	50,503	0.00%	0.12%	0.115%
Summer Night	SN33	4	0	11,382	0.00%	0.03%	0.026%
Winter Day	WD33	4	0	58,498	0.00%	0.13%	0.133%
Winter Night	WN33	4	0	4,688	0.00%	0.01%	0.011%
Category 3.4							
Anytime Demand	AnyDem34	138	492,330	1,809,093	1.12%	4.12%	5.242%
RCPD Demand	WinDem	148					
Summer Day	SD34	138	0	586,166	0.00%	1.34%	1.335%
Summer Night	SN34	138	0	107,043	0.00%	0.24%	0.244%
Winter Day	WD34	138	0	1,166,876	0.00%	2.66%	2.658%
Winter Night	WN34	138	0	85,737	0.00%	0.20%	0.195%
Category 3.5							
Anytime Demand	AnyDem35	2	57,601	198,367	0.13%	0.45%	0.583%
RCPD Demand	WinDem	148					
Summer Day	SD35	2	0	54,193	0.00%	0.12%	0.123%
Summer Night	SN35	2	0	15,343	0.00%	0.03%	0.035%
Winter Day	WD35	2	0	135,127	0.00%	0.31%	0.308%
Winter Night	WN35	2	0	11,845	0.00%	0.03%	0.027%
Power Factor Charge (where applies)							
All Group 3 Categories	kVAr	3	0	12,076	0.00%	0.03%	0.028%
Large Category fixed charge only	Excl Irr						
Cat 6.1		1	1,815,008	214,575	4.13%	0.49%	4.623%
Cat 6.2		1	362,829	229,973	0.83%	0.52%	1.350%
CB		1	318,948	1,308,853	0.73%	2.98%	3.708%
All pricing			**15,246,084**	**28,656,378**	**34.73%**	**65.27%**	**100.00%**

Appendix D: Directors' Certificate

networktasman
Your consumer-owned electricity distributor

Network Tasman Limited
52 Main Road, Hope 7020
PO Box 3005
Richmond 7050
Nelson, New Zealand

Tel: 64 3 989 3600
Freephone: 0800 508 098
Fax: 64 3 989 3631
Email: info@networktasman.co.nz
Website: www.networktasman.co.nz

Commerce Act (Electricity Distribution Services Information Disclosure) Determination 2012

Schedule 17

Certification for Year-beginning Disclosures

Clause 2.9.1 of section 2.9

We, Michael John McCliskie and Sarah-Jane Ellen Weir being directors of Network Tasman Limited certify that, having made all reasonable enquiry, to the best of our knowledge –

(a) The following attached information of Network Tasman Limited prepared for the purposes of clause 2.4.1 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.

Date 31-3-16

Date 31. 3. 16.