NetworkTasman

PRICING METHODOLOGY DISCLOSURE

For Year Commencing 1 April 2014

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
P O Box 3005
RICHMOND 7050

1.0 REGULATORY REQUIREMENT

1.1 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 owners 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

1.2 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.

2.0 COMMERCE ACT PRICE CONTROL

2.1 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.

2.2 Being a controlled entity NTL is subject to starting price adjustments (Po) at the commence 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 but currently restricts annual movements for the distribution component of line prices to the annual rate of inflation (CPI).

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

2.4 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 2015.

2.5 The Commission assessed NTL's Po adjustment for 1 April 2013 to be +9% however the company has chosen not to uplift this allowance in 2013-15 period for reasons explained in section 7.6.

3.0 FINANCIAL INFORMATION

3.1 This pricing disclosure relies on financial information drawn from NTL's line business budget and financial forecasts for the year ending 31 March 2015. Line business costs are separated from NTL's other non-line business activities in a manner consistent with the Electricity Information Disclosure Determination 2012 .

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

3.3 Network capital costs are calculated using:
- The Commerce Commission's estimate of WACC for EDB's subject to DPP control for the 5 year period between 2010 and 2015, and
- NTL's forecast Regulatory Asset Base (RAB) to be included in Information Disclosures as at 31 March 2014.

The RAB is based on the 2004 certified ODV of systems fixed assets and has been rolled forward to 31 March 2014 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 2014.

4.0 NETWORK TASMAN PRICING PRINCIPLES & STRATEGY

4.1 NTL's pricing methodology reflects, to the extent possible:
- The pricing principles stated in NTL's Statement of Corporate Intent 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 (EA).

4.2 The following pricing objectives are stated in NTL's SCI (available on website) and are incorporated in Use of Systems Agreements with retailers. They provide a high level overview of NTL's forward pricing intentions and 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 NT Trust as part of the SCI process.

4.3 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/

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

5.0 LINE CHARGE DERIVATION

5.1 Line charges are the sum of distribution charges and transmission charges. Each component has different underlying cost drivers and so distribution and transmission pricing components are derived separately.

6.0 PRICING FOR DISTRIBUTION SERVICES

6.1 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

7.0 NTL DISTRIBUTION REVENUE REQUIREMENT

7.1 The Distribution Revenue Requirement (DRR) for an EDB is the sum of:

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

7.2 NTL accumulates distribution costs in 7.1 above 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

7.3 The sum of these costs equates to the line business's total DRR and its upper bound is constrained by the DPP & Po controls administered by the Commerce Commission.

7.4 Information on NTL's 2014-15 DRR by cost classification and load group is provided in Appendix A.

7.5 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.

7.6 The cost of capital (WACC) is derived using the Capital Asset Pricing Model. For the financial year commencing 1 April 2014 NTL, as a price controlled EDB, has used the Commerce Commission's WACC for the 5 year DPP price control period ending 31 March 2015. The Commission also used this WACC for the Po reset applicable 1 April 2013. The parameters used by the Commission in setting WACC were :

- 5 year government stock rate at 5.31%for estimate of the risk free rate
- Target capital structure of 44% debt to total assets
- Cost of debt 7.93%
- Asset beta of 0.34 as the measure of EDB's systematic risk
- post tax market risk premium for equity of 7.1%
- corporate tax rate of 28.0%

Based on these inputs the Commission's 75th percentile estimate of WACC was 8.77% post tax. NTL has applied an average pre-tax WACC of 11.50% to its line business assets (RAB) in determining DRR.

7.7 Current interest rates would materially reduce the Commission's WACC estimate if recalculated as at 1 April 2014. In light of this and the fact that interest rates forecasts remaining low, NTL has chosen not to uplift the DPP price path headroom available from the Po reset for FYE March 2014 and 2015. Should interest rates stay around current levels for the next Po reset on 1 April 2015, NTL's current +9% Po adjustment and associated DPP headroom is likely to be largely reversed out. Consequently NTL has moved its distribution pricing by about CPI for each of the 2013-14 and 2014-15 pricing years as this should better serve consumers than a 9% increase on 1 April 2013 followed by a significant Po decrease in 2015.

8.0 LOAD GROUPS

8.1 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.

8.2 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

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.

8.3 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.

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

9.0 ALLOCATION OF NETWORK COSTS TO LOAD GROUPS

9.1 Direct Network Costs, Systems Depreciation and Capital Costs

Direct network costs, systems depreciation and capital costs are directly assignable to the network asset categories as shown in Figure 3.1 below.

9.2 These network costs are then accumulated into those associated with the upper & lower segments of the network as shown in Figure 3.2.

9.3 Using the Figure 3.3 formulae, the network costs accumulated to the upper and lower network segments are apportioned to each load group on the basis of coincident maximum demand (CMD), calculated on a 3 year rolling average basis at each GXP.

9.4 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.

9.5 A key difference between the treatment of the upper and lower network cost allocations to Groups is 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.

FIGURE 3.1 ALLOCATION OF DIRECT COSTS TO COMPONENTS OF THE NETWORK

NETWORK COMPONENT	DIRECT NETWORK COSTS	DEPRECIATION	RETURN ON ASSETS	TOTAL DIRECT COST (TDC)
General 400V lines	a1	b1	r1	c1
Distribution transformers	a2	b2	r2	c2
General 11 kV lines	a3	b3	r3	c3
Dedicated 11 kV lines	a4	b4	r4	c4
Sub transmission. lines and zone subs.	a5	b5	r5	c5
Dedicated networks	a6	b6	r6	c6
TOTALS	**a**	**b**	**r**	**C**

FIGURE 3.2 NETWORK UPPER AND LOWER NETWORKS

NETWORK COMPONENT	TDC BY COMPONENT	UPPER NETWORK ALLOCATION	LOWER NETWORK ALLOCATION
General 400V lines	c1	d1	e1
Distribution transformers	c2	d2	e2
General 11 kV lines	c3	d3	e3
Dedicated 11 kV lines	c4	d4	e4
Sub transmission. lines and zone subs	c5	d5	e5
Dedicated networks	c6	d6	e6
TOTALS	**C**	**D**	**E**

Where : d1& d2 =0 and e5,& e6 =0

FIGURE 3.3 ALLOCATION OF DIRECT NETWORK COSTS TO LOAD GROUPS

Load Group	Supply Voltage V	Coinci dent Deman	Accumulated Formula MVA	Cost Allocation Formula	Total Direct Cost Allocation By Group
(G1) 400V Gen < = 15 kVA	230/400	M1	A1	(M1/A6*D)+(M1'/A3*E)	TDC 1
(G2) 400V Gen >15&<150kVA	400	M2	A2	(M2/A6*D)+(M2'/A3*E)	TDC 2
(G3) 400V &11kV > 150 kVA	400/11,00O	M3	A3	(M3/A6*D)+(M3'/A3*E)	TDC 3
(G6) Dedicated. Network	Over 11,000	M6	A6	(M6/A6*D)	TDC 6

Note: A1 = M1, A2 = M1+M2, A3=M1+M2+M3 etc.

M1', M2', M3' are CMD's adjusted to reflect G3 minimal use of the 400V lower network assets

9.6 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 consumers.
- 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 more arbitrary than for direct costs. Allocator based on installed fuse capacity provides a reasonable balance between allocating by customer numbers and allocating by some measure of demand

FIGURE 3.4 LOAD GROUP REVENUE REQUIREMENT

Load Group	Supply Voltage	Total Direct Cost Allocation	Total General Overhead Allocation	Total Distribution Revenue Requirement
(G1) 400V Gen < = 15 kVA	230/400	TDC 1	OH1	DDR1 = TDC 1+OH1
(G2) 400V Gen > 15 & < 150 kVA	400	TDC 2	OH2	DDR2 = TDC 2+OH2
(G3) 400V &11kV > 150 kVA	400/11,000	TDC 3	OH3	DDR3 = TDC 3+OH3
(G6) Dedicated. Network	Over 11,000	TDC 6	OH6	DDR6 = TDC 6+OH6

10.0 DERIVATION OF DISTRIBUTION TARIFFS.

10.1 General

The DDRi totals from Figure 3.4 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).

10.2 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

(a) 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.

(b) Government policy and regulations compel ELBs 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.

(c) 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 generally prefer broad based kWh based charges, simple fixed daily charges and low numbers of tariff codes .

(d) NTL engagement with consumers reveals 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.

(e) As a compromise to the conflicting expectations above, NTL’s longer term goal is 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 will raise Group 1& 2 fixed charges in preference to higher variable charges as a better means of reflecting underlying supply costs.

(f) Existing metering technology limitations mean that for all but about 1% of NTL's 37,700 ICP's billing metrics are restricted to
- kWh consumption in monthly intervals
- installed fuse size or
- fixed daily charges.

For mass market ICP's 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.

(g) 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 Group 1 pricing no longer reasonably reflects the fixed costs of supply to poor load factor or remotely located consumers in this group. Just 11% 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 Winter 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).

10.3 Fixed and Capacity based Tariffs by Group

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

(b) 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.

(c) 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 Winter 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.

10.4 **Variable/Consumption based Tariffs**

(a) Variable line tariffs are expressed as "cents per kWh" and apply to all consumer groups, except Group 6.

(b) 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 intruptability / restrictions the consumer commits to in advance.

10.5 **Revenue Adequacy**

(a) The distribution revenue requirement for each group, (DRR1 to DRR6 in Figure 3.4) 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.

(b) 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. There is no cross subsidies between customer Groups

11.0 DISTRIBUTION PRICES - Group 1

11.1 Group 1 distribution revenue requirement DRR1 is split between that part to be recovered by a fixed charge (FC1), and that part to be recovered by a variable charge (VC1).

11.2 The total annual fixed charge FC1 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, FC1, 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.

11.3 The fixed charge FC1 recovers only 11% of the distribution revenue DRR1 to be raised from Group 1

11.4 The total variable charge VC1 recovers the residual 89% of revenue from DRR1

11.5 Variable tariff rates are determined by dividing the number of units consumed by Group 1 into VC1 and applying a set of relative weightings between the tariff types on offer.

11.6 The relative weights are in part driven by legacy issues but also reflect the relative costs of providing network services at "peak" verse "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 off peak rates are set to be less than half the standard anytime rate.

Load Group 1 : 2014-15 Budget Data

DRR1 budgeted 2014-15	=	$14,300,000
Number of G1 ICPs (forecast)	=	34,920
Total to be recoverable by fixed charges		
Fixed charge per annum	=	$43.25 pa. or 11.85 cents /day
	=	34,920*$43.25
FC1	=	$1,510,000
Total Variable Charge:	=	$14,300,000 - $1,510,000
VC1	=	$12,790,000

Group 1 Variable Tariffs

Total $ to be recovered from variable charges from Group 1

VC1 = $12,790,000

Tariff s G1	Allocated Weightings	G1 Budgeted Units
A - Anytime	100%	171.3 GWh
B - Day	110%	1.6 GWh
C - Controlled Water	46%	61.4 GWh
D - Night	33%	4.8 GWh

Line Charge Tariff A = $12,790,000 / (171.0*1.0 +1.6* 1.10+61.4 * 0.46+4.8*0.33)
= 6.29 cents per kWh of A metered consumption

Line Charge Tariff B = $0.0629 * 1.10
= 6.91 cents per kWh of B metered consumption

Line Charge Tariff C = $0.0629 * 0.46
= 2.92 cents per kWh of C metered consumption

Line Charge Tariff D = $0.0629 * 0.33
= 2.08 cents per kWh of D metered consumption

12.0 DISTRIBUTION PRICES - Group 2

12.1 Group 2 distribution revenue requirement DRR2 is split between that to be recovered by a fixed capacity charge (FC2), and that part to be recovered variable charges (VC2).

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

12.3 Group 2 fixed charge revenue is targeted at 25% of DDR2 or 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 scare network capacity efficiently.

12.4 The total fixed charge revenue (FC2) 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.

12.5 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.

12.6 The total variable charge (VC2) recovers the residual revenue of DRR2 using variable common tariff rates as shown above for Group 1 .

Load Group 2 data from 2014-15 Budget Data:

Consumer	AMD (kVA)
x	40
y	70
z	110
....	....
Total Group 2	116,300 kVA

Group 2 DRR2 Budget 2014-15	$7,005,000
Total Fixed Charge FC2 ~ 22%	$1,485,000
Total Variable Charge VC2 ~78%	$5,520,000

Capacity Tariff = $1,485,000 / 116,300
= $12.78 per kVA pa or 3.50cents/kVA/day.

Consumer "x" AMD Charge / day = (12.78 * 40) / 365
= $1.40 per day

Group 2 Variable Tariffs

Total $ to be recovered from variable charges in Group 2
VC2 = $7,005,000 – $1,485,000
= $5,520,000

Tariff s G2	Allocated Weightings	G2 Budgeted Units
A - Anytime	100%	66.8 GWh
B - Day	110%	17.4 GWh
C - Controlled Water	46%	3.9 GWh
D - Night	33%	7.6 GWh

Line Charge Tariff A = $5,520,000 / (66.8*1.0 +17.4* 1.10+3.9 * 0.46+7.6*0.33)
= 6.09 cents per kWh of A metered consumption

Line Charge Tariff B = $0.0609 * 1.10
= 6.69 cents per kWh of B metered consumption

Line Charge Tariff C = $0.0609 * 0.46
= 2.82 cents per kWh of C metered consumption

Line Charge Tariff D = $0.0609 * 0.33
= 2.01 cents per kWh of D metered consumption

12.7 **Group 2 Low User Tariff (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 8000kWh 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 8000 kWh per annum but is poorly reflective network supply costs.

12.8 **High Load Factor Tariff (HLFC)**: From 1 April 2012 NTL offered a pricing option suitable for mass market customers with high load factors. The tariff was introduce 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.

13.0 DISTRIBUTION PRICES - Group 3.

13.1 Group 3 distribution revenue requirement DRR3 is split between that part recoverable by a capacity charges (FC3) and that recoverable by a variable charge (VC3).

13.2 Group 3 customers are primarily larger, high load factor business consumers and so the fixed capacity based charges for this group are set to recover approximately 50% of DRR3. 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 .

13.3 At the beginning of the billing year the consumer's AMD and Winter RCPD are measured directly from TOU data supplied by retailers:

- A G3 customers Winter RCPD quantity is the average of the consumers kW load measured coincident with Transpower's 12 peak loads on USI grid for the year ending 31st August in the previous year.
- A G3 customer's AMD is that consumers highest half hourly kVA at any time, in any month, during the year.

13.4 The total fixed charge revenue FC3 is divided by the sum of the AMDs and the Winter 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 Winter RCPD kW as distribution tariffs .

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

13.6 The total variable charge (VC3) recovers the residual revenue from DRR3 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 discount in comparison to Winter Day rates reflecting the lower loads on the network during these time periods.

Load Group 3: Category 3.4 2014-15 Budget Data :

Consumer	AMD	Winter RCPD
x	225	100
y	194	120
Group Total	37,686	15,054

Total Group 3 Dist Revenue - DRR3	$3,994,000
Fixed Charge recovery % approx.	48%
Total Demand Based Revenue - FC3	$1,913,000
Total Variable Charge Revenue-VC3	$2,081,000
AMD tariff % FC3	91%

AMD Tariff	=	($1,913,000 * 0.91)/37,686
	=	$46.10 per kVA pa. or 12.63 cents/kVA/day
WMD Tariff	=	($1,913,000*0.09)/15,054
	=	$11.70 per kW pa. or 3.19cents/kW /day

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Consumer Capacity Charges

Consumer "x" Winter RCPD	=	100 * 11.70 / 12
	=	$98 per month
Consumer "x" AMD Charge	=	225 * 46.10 / 12
	=	$864 per month

(The Variable charge per tariff is calculated in the same manner as for Group 1&2)

14.0 DISTRIBUTION PRICES - Group 6.

14.1 There are only 2 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.

14.2 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.

14.3 The methodology for allocating distribution costs, RAB values and determining the distribution revenue requirement for these consumers is describe in Section 9 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.

14.4 The Group 6 annual distribution revenue requirement, DRR6, 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.

15.0 PRICING FOR TRANSMISSION SERVICES

15.1 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.

16.0 NTLs TRANSMISSION REVENUE REQUIREMENT

16.1 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.

17.0 ALLOCATION OF TRANSMISSION COSTS TO LOAD GROUPS.

17.1 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.

17.2 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.

17.3 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.

17.4 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.

18.0 DERIVATION OF TRANSMISSION TARIFFS.

18.1 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 8.0)

(b) Transmission costs for Group 6 and Bulk Supply customers are recovered on a direct pass through basis (see Section 21.0).

(c) The remaining transmission costs, after Group 6 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:

(i) "dollars per kW of Winter RCPD” This Winter RCPD component directly passes through Transpower’s Interconnection charges attributable to Group 3 consumers

(ii) “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 intruptability / restrictions the consumer commits to in advance.

19.0 TRANSMISSION PRICES – GROUPS 1 – 3 Fixed / Capacity

19.1 Group 1

The total transmission cost attributable to Group 1 (TT1) is split between that part to be recovered by a fixed charge (TFC1) and that part to be recovered by a variable charge (TVC1).

The total fixed charge (TFC1) 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)

19.2 Group 2

The total transmission cost attributable to Group 2 (TT2) is split between that part relating to connection and new investment charges to be recovered by a fixed charge (TFC2), and that part to be recovered by a variable charge (TVC2) 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 Sections 12.2-12.5 above.

The total fixed charge (TFC2) 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.

19.3 **Group 3**
The total transmission cost allocated to Group 3 (TT3) is recovered by fixed charges (TFC3a and TFC3b).

The connection and new investment component attributable to Group 3 (TFC3a) 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 (TFC3b) are recovered based on individual customers demands measured coincident with the USI RCPD demand periods recorded over the previous year (Winter RCPD).

The total amount recoverable by the Winter RCPD charge (TFC3b), is divided by the total Winter RCPD kWs for the Group. This gives a dollar tariff per kW of Winter RCPD. The dollar per Winter RCPD tariff is then multiplied by each ICP's metered Winter RCPD kW to give the ICP's annual charge and is divided by 12 and billed monthly.

20.0 TRANSMISSION PRICES - GROUPS 1-3 Variable

20.1 Group 1&2 variable charge amounts TVC1 and TVC2 and are recovered using variable transmission tariff rates in a manner similar to G1&2 distribution charges.

20.2 Each variable 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.

20.3 A relative weighting is applied to differentiate peak and non-peak variable 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.

20.4 The total amount to recover by variable transmission tariffs TVC1 or TVC2 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.

20.5 The variable transmission tariff rates 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.

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

Transmission Cost Recovery: 2014-15 Budget Data

	Total
Group 1 RCPD 2013	52,117 kW
Group 2 RCPD 2013	14,215 kW
Group 3 RCPD 2013	17,795 kW
Group 6 RCPD 2013	17,236 kW
RCPD at GXPs 2013	101,363 kW

TFC1	=	$402,000
TVC1	=	$6,345,000
TTC1	=	$6,747,000
TFC2	=	$666,000
TVC2	=	$2,098,000
TTC2	=	$2,764,000
TT3	=	$2,686,000

Group 1 ICPs	34,920
Group 2 AMD	116,300 kVA
Group 3 AMD	45,654 kVA
Group 3 Winter RCPD 2013	18,761 kW

G1 Fixed Charge	=	$398,000 / (34,920) / 365 * 100
	=	3.15 cents per day
G2 Fixed Charge	=	$666,000 /116,300/365
	=	$5.73 per kVA pa. or 1.57 cents /kVA/day

Group 1 Variable Transmission Tariffs

Tariff s Common to G1& G2	Allocated Weightings	G1 Budgeted Units
A - Anytime	100%	171.3 GWh
B - Day	110%	1.6 GWh
C - Controlled Water	45%	61.4 GWh
D - Night	34%	4.8 GWh

Variable Tariff A	=	$6,345,000 / (171.0*1.0 +1.6* 1.10 +61.4 * 0.45 +4.8*0.33)
	=	3.13 cents per kWh of A metered consumption
Variable Tariff B	=	$0.0313 * 1.10
	=	3.45 cents per kWh of B metered consumption
Variable Tariff C	=	$0.0313 * 0.45
	=	1.42 cent per kWh of C metered consumption
Variable Tariff D	=	$0.0313 * 0.34
	=	1.06 cents per kWh of D metered consumption

Group 2 variable tariff rates - are determined in a similar manner

Group 3

TFC3a Connection	=	$ 578,000
TFC3b Interconnection	=	$2,108,000
TT3 Total	=	$2,686,000

G3 Fixed Charges

TFC3a Connection	=	$578,000 / 45,654
	=	$12.66 per kVA pa of AMD or 3.47 cents / kVA/day
TFC3b Interconnection	=	$2,108,000 /18,761
	=	$112.36 per kW of Winter RCPD/ pa. or 30.79 cents/kW/day

21.0 TRANSMSSION PRICES - GROUP 6 & BULK SUPPLY .

21.1 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

21.2 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.

Group 6 Budget Data 2014-15
Connection & NIA Charge Allocation -
For Stoke GXP :

Transpower Connection & NIA Charges Stoke GXP	=	$921,000 pa
Chargeable AMD for Stoke GXP 2013-14	=	122,249 kVA
Group 6 Consumers CMD @ Stoke GXP 2013-14	=	19,842 kVA
G6 Consumers Transmission Connection Charge	=	19,842/122,249 * $921,000
	=	$149,500 pa. or $12,460 / month

21.3 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.

21.4 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.

21.5 The transmission charges described above are passed through to the two Group 6 and one Bulk Supply customer under letters of agreement in a fully 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.

22.0 DISTRIBUTED GENERATION

22.1 NTL has 4 small hydro generators connected to and embedded within its network. It also has 180 roof top solar generation plants connected and injecting into the network.

22.2 NTL uses regulated terms as a default contract with the small roof top solar plants but has more formal connection agreements with the 4 larger 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.

22.3 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.

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

22.5 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

22.6 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 / demand based charges combined with a reduction in variable tariff rates, where this possible
- time of use based pricing when metering technology permits
- introduction of a variable tariff applied against export energy injected into the network

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

22.8 Where time of use meters are installed at DG sites NTL will pass through any avoided transmission Interconnection charges attributable to the embedded generator. Under the current transmission pricing methodology this is based on the generators half hourly injected kWs measured coincident with the 12 peak RCPD half hourly demand periods annually measured for the Upper South Island. NTL passes through the full value of the avoided interconnection charges ($114 / kW for 2014-15) 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.

22.9 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.

23.0 DISTRIBUTION PRICING PRINCIPLES & INFORMATION DISCLOSURE GUIDELINES

23.1 The Electricity Authority has 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.

23.2 In the following sections:

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

<u>Pricing Principles</u>

(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 37,700 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 cost 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 (over build) 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 regulators WACC on the RAB value of its systems fixed assets
- the real costs of overbuild would be well in excess of the regulators Replacement Cost (RC) of NTL's network (generally regulatory RC's are considered understated).
- NTL's systems asset RC of $331m is well over twice the RAB of $153m; data from 31 March 2013 Information Disclosures.
- 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 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.

Incremental Cost Test

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 & reinforce the core network.

NTL 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 (have been strengthened in 2013-15) 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 2 out NTL top 130 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 providing 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 21,000 domestic customers qualify for the low user tariff on NTL's network).
- Thirdly, there is 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; consumers tend to see and react to delivered electricity pricing signals rather than the individual line and energy components. From 1 April 2014 NTL's mass market consumers'(Group1&2 or about 97% of NTL's 37,700 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 1consumers

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 elasticity's 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 65-75%. 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 "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 37,500 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 off its SCI and 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, in full, any demonstrable saving in transmission interconnection charges (circa $114/kW) 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 (circa ($114 / kW) 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 $58/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 are likely to be reversed in 2015
- NTL pricing 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 (covers circa 34,800 out of NTL's 37,700 ICPs). 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 (i.e. the 5 core tariffs in Group 1 are used by 34,900 out of NTL's 37,700 ICP's)
- The regulated low user tariff has been applied across all 34,900 Group 1 ICP's making line pricing decisions for 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 23 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 the 37,500 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 127 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.

23.3 The Information Disclosure Guidelines and NTL's general compliance with them is discussed below :

<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 2014-15 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 Section 23 of this document.
(ii) the rationale for consumer groupings and the method for determining the allocation of consumers to the consumer groupings;
Sections 8.0 - 8.4 explain 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 6.0- 7.7 for description of distribution costs and revenue components. See Section 16.0-17.4 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 9.0 – 9.5 for description of the methodology for allocation of distribution costs to consumer Load Groups. See Section 17.1 – 17.4 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 2014-15.
(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 Sections 9.0-13.2 for description of distribution tariff components & derivation. See Sections 18.0-21.3 for description of transmission tariff components & derivation. See Appendix A for NTL tariff data for 2013-14.
(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 reward via pass through at full value of any 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

Changes made to the 2014-15 Pricing Methodology and the associated changes to price and target revenues are as follows:

1. NTL has increased the distribution component of line charges by 3.1% for Group 1 consumers and by 2.3% for most other consumers (circa $600,000 of additional revenue) which is consistent with the CPI and headroom allowance under the DPP control regime This provides an offset to the normal annual increases in line business operating and overhead costs. G1 prices have been increased more than other groups to more closely align their economic returns up closer to the other groups.
2. NTL has increased the transmission component of line charges to all consumer groups to the extent necessary to recover increased transmission costs attributable to each Group in 2014-15. Transmission costs attributable to mass market customers have increased circa 3.0% or $300k for 2014-15 due to a reduction in chargeable demand that has been more than offset by higher transmission pricing from 1 April 2014. Group 3 and Group 6 transmission costs are determined on a direct pass through basis using each ICP's metered RCPD coincident volumes and have increased 17% and 3% respectively.
3. The transmission component of Group 2 fixed charges has been adjusted to enable full recovery of Transpower fixed connection and new investment charges attributable to this Group. Interconnection charges attributable to Group 2 are recovered through variable kWh tariff rates.
4. NTL separated Group 1 and Group 2 variable (kWh) tariffs for the first time in 2013-14 because the fixed charges in Group 1 are suppressed by the blanket application of the low user regulatory tariff structure in this Group. This places undue upward pressure on kWh variable tariffs because all annual pricing adjustments can only be applied to the kWh variable tariff rates. This pressure should be isolated within Group 1, which is predominately domestic consumers, rather than spilling over to Group 2 as has occurred when Groups 1&2 previously shared common kWh variable tariff rates. Group 2 capacity charges in 2014-15 have been increased relatively more than variable tariffs in accord with NTL policy of increasing reliance over time on fixed and demand based charges.
5. Year on year changes in the components of revenue and costs can be ascertained from comparative data in Appendix A

Appendix A

THE ELECTRICITY DISCLOSURE DETERMINATION 2012

Requirement 2.4.3 Disclosure of Pricing And Related Information

LOAD GROUP STATISTICS USED IN PRICING METHODOLOGY

For year commencing: 1 April 2014

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	34,919	51,671	523,785	52,117	175,371,959	68,358,369	243,730,327	$ 78.91
Group 2	2,680	26,643	119,163	14,215	90,917,114	12,917,015	103,834,129	$ 47.05
Group 3	134	23,502	44,242	17,795	96,241,287	35,499,623	131,740,911	$ 25.57
Group 6	2	19,464	26,553	17,236	N/A	N/A	124,567,442	$ 2.73
Bulk supply	1	N/A	31,292	29,587	N/A	N/A	151,240,902	$ -
Total	**37,736**	**121,280**	**745,035**	**130,950**			**755,113,712**	**$ 154.26**

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

LOAD GROUP STATISTICS USED IN PRICING METHODOLOGY

For year commencing: 1 April 2013

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	$m
Group 1	34,586	51,180	518,790	54,284	175,371,959	68,358,369	243,730,327	$ 84.67
Group 2	2,684	28,422	120,033	19,338	90,917,114	12,917,015	103,834,129	$ 47.87
Group 3	123	22,557	44,242	16,362	95,705,880	35,416,554	131,122,434	$ 23.78
Group 6	2	19,730	26,553	18,795	N/A	N/A	124,567,442	$ 2.59
Bulk supply	1	N/A	31,292	28,196	N/A	N/A	151,240,902	$ -
Total	**37,396**	**121,889**	**740,910**	**136,975**			**754,495,235**	**$ 158.91**

SEPARATION OF ESTIMATED REVENUE AND COSTS COMPONENTS TO LOAD GROUPS

For the year commencing 1 April 2014.

Customer Group	Transmission Costs	Direct NW Costs	Indirect NW Costs	Depreciation	Allowable PreTax Return on RAB	TRR Total Revenue Requirement	Targeted Budget Line Revenue	Revaluations @ CPI = 1.7%	Over / (Under) Recovery vs TRR
	$	$	$	$	$	$	$		
Group 1	$ 7,151,902	$ 3,384,054	$ 2,118,279	$ 3,397,379	$ 8,641,274	**$ 24,692,889**	**$ 21,783,532**	**$ 1,316,649**	**$ (1,592,708)**
Groups 2 & HLF	$ 2,258,894	$ 1,904,517	$ 481,916	$ 1,912,016	$ 5,375,530	**$ 11,932,874**	**$ 10,393,744**	**$ 785,028**	**$ (754,102)**
Group 3	$ 2,557,830	$ 1,196,854	$ 364,481	$ 1,201,567	$ 2,971,596	**$ 8,292,328**	**$ 7,326,536**	**$ 426,559**	**$ (539,233)**
Group 6	$ 2,011,441	$ 78,067	$ 48,000	$ 128,878	$ 331,506	**$ 2,597,891**	**$ 2,504,296**	**$ 45,565**	**$ (48,031)**
Bulk supply	$ 3,499,841	$ -	$ 4,000	$ -	$ -	**$ 3,503,841**	**$ 3,499,841**	**$ -**	**$ (4,000)**
Total	**$ 17,479,908**	**$ 6,563,492**	**$ 3,016,677**	**$ 6,639,840**	**$ 17,319,906**	**$ 51,019,823**	**$ 45,507,948**	**$ 2,573,801**	**$ (2,938,074)**

For the year commencing 1 April 2013.

Customer Group	Transmission Costs	Direct NW Costs	Indirect NW Costs	Depreciation	Allowable PreTax Return on RAB	TRR Total Revenue Requirement	Targeted Budget Line Revenue	Revaluations (@ CPI=1.7%)	Over / (Under) Recovery vs TRR
	$	$	$	$	$	$	$		
Group 1	$ 6,595,535	$ 3,755,760	$ 1,957,589	$ 3,568,172	$ 9,298,924	**$ 25,175,980**	**$ 21,397,861**	**$ 1,413,624**	**$ (2,364,495)**
Groups 2 & HLF	$ 2,617,782	$ 2,006,570	$ 452,929	$ 1,906,348	$ 5,469,150	**$ 12,452,780**	**$ 10,062,386**	**$ 799,207**	**$ (1,591,187)**
Group 3	$ 2,132,517	$ 1,077,048	$ 328,519	$ 1,023,253	$ 2,763,768	**$ 7,325,106**	**$ 6,640,992**	**$ 396,978**	**$ (287,136)**
Group 6	$ 1,955,035	$ 66,325	$ 60,000	$ 106,829	$ 311,370	**$ 2,499,560**	**$ 2,437,168**	**$ 43,248**	**$ (19,144)**
Bulk supply	$ 2,986,027	$ -	$ 4,000	$ -	$ -	**$ 2,990,027**	**$ 2,986,027**	**$ -**	**$ (4,000)**
Total	**$ 16,286,897**	**$ 6,905,703**	**$ 2,803,038**	**$ 6,604,603**	**$ 17,843,213**	**$ 50,443,454**	**$ 43,524,434**	**$ 2,653,058**	**$ (4,265,962)**

Electricity Information Disclosure Determination 2012

Section 2.4.18: Disclosure of Line Charges.

Network Tasman Limited Pricing Effective from 01 April 2014

Price/Tariff Description	0	Approx No of ICPs	Units	Distribution 2014-15	Transmission 2014-15	Total 2014-15	Distribution 2013-14	Transmission 2013-14	Total 2013-14
Group 0 (unmetered)									
Low capacity - Electric fences, Comms etc	0UNM	95	c/day	35.00	19.00	**54.00**	34.00	19.00	**53.00**
Streetlight only connection	0S	27	c/day	0.00	0.00	**0.00**	0.00	0.00	**0.00**
Temporary box	0TBS	96	c/day	91.00	44.00	**135.00**	90.00	44.00	**134.00**
Streetlight attached	0STL	164	c/W/day	0.079	0.039	**0.118**	0.078	0.038	**0.116**
Metered supplies, 15-150 kVA Capacity									
Group 1 15kVA capacity									
Daily Charge	1	34,839	c/day	11.85	3.15	**15.00**	11.85	3.15	**15.00**
Anytime Continuous	1ANY	34,049	c/kWh	6.29	3.13	**9.42**	6.08	3.04	**9.12**
Day (of Day/Night)	1DAY	312	c/kWh	6.91	3.45	**10.36**	6.68	3.35	**10.03**
Night	1NIT	2,368	c/kWh	2.08	1.06	**3.14**	2.01	1.03	**3.04**
Off Peak Controlled	1OPK	212	c/kWh	4.93	2.39	**7.32**	4.77	2.32	**7.09**
Controlled Water	1WSR	25,776	c/kWh	2.92	1.42	**4.34**	2.82	1.38	**4.20**
Group 2 20-150 kVA									
Capacity (Except domestic low users)	2	2,626	c/kVA/day	3.50	1.57	**5.07**	3.35	1.52	**4.87**
Anytime Continuous	2ANY	2,173	c/kWh	6.09	2.31	**8.40**	5.99	2.28	**8.27**
Day (of Day/Night)	2DAY	446	c/kWh	6.69	2.56	**9.25**	6.58	2.52	**9.10**
Night	2NIT	496	c/kWh	2.01	0.78	**2.79**	1.98	0.77	**2.75**
Off Peak Controlled	2OPK	37	c/kWh	4.78	1.77	**6.55**	4.70	1.74	**6.44**
Controlled Water	2WSR	679	c/kWh	2.82	1.06	**3.88**	2.78	1.04	**3.82**
Group 2 Domestic LFC, < 40kVA capacity									
Group 2 Domestic low users < 40kVA.	2LLFC	22	c/day	11.85	3.15	**15.00**	11.85	3.15	**15.00**
Anytime Continuous	2LANY	21	c/kWh	8.28	4.02	**12.30**	8.12	3.90	**12.02**
Day (of Day/Night)	2LDAY	3	c/kWh	8.71	4.44	**13.15**	8.54	4.31	**12.85**
Night	2LNIT	7	c/kWh	5.33	1.36	**6.69**	5.18	1.32	**6.50**
Off Peak Controlled	2LOPK	0	c/kWh	7.38	3.07	**10.45**	7.21	2.98	**10.19**
Controlled Water	2LWSR	12	c/kWh	5.95	1.83	**7.78**	5.79	1.78	**7.57**
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	12.85	4.02	**16.87**	12.57	3.90	**16.47**
Day (of Day/Night)	2HDAY	0	c/kWh	13.28	4.44	**17.72**	12.99	4.31	**17.30**
Night	2HNIT	0	c/kWh	9.90	1.36	**11.26**	9.63	1.32	**10.95**
Off Peak Controlled	2HOPK	0	c/kWh	11.95	3.07	**15.02**	11.66	2.98	**14.64**
Controlled Water	2HWSR	0	c/kWh	10.52	1.83	**12.35**	10.24	1.78	**12.02**
Group HLF (15 - 150kVA)									
Capacity Charge	HLF	42	c/kVA/day	31.78	9.04	**40.82**	30.41	8.73	**39.14**
Anytime Continuous	HLFANY	28	c/kWh	1.67	0.63	**2.30**	1.64	0.62	**2.26**
Day (of Day/Night)	HLFDAY	17	c/kWh	1.81	0.69	**2.50**	1.78	0.68	**2.46**
Night	HLFNIT	17	c/kWh	0.52	0.20	**0.72**	0.51	0.20	**0.71**
Off Peak Controlled	HLFOPK	8	c/kWh	1.30	0.49	**1.79**	1.28	0.48	**1.76**
Controlled Water	HLFWSR	8	c/kWh	0.75	0.28	**1.03**	0.74	0.28	**1.02**
Generation (all groups/categories)	GENA	180	c/kWh	0.00	0.00	**0.00**	0.00	0.00	**0.00**
GROUP 3. TOU metered, ≥150 kVA									
Category 3.1									
Anytime Demand	AnyDem31	4	c/kVA/day	9.01	3.47	**12.48**	8.71	3.27	**11.98**
RCPD Demand	WinDem	137	c/kW/day	3.19	30.79	**33.98**	3.12	27.65	**30.77**
Summer Day	SD31	4	c/kWh	0.44	0.00	**0.44**	1.78	0.00	**1.78**
Summer Night	SN31	4	c/kWh	0.24	0.00	**0.24**	0.51	0.00	**0.51**
Winter Day	WD31	4	c/kWh	0.79	0.00	**0.79**	1.28	0.00	**1.28**
Winter Night	WN31	4	c/kWh	0.24	0.00	**0.24**	0.74	0.00	**0.74**
Category 3.3									
Anytime Demand	AnyDem33	4	c/kVA/day	11.84	3.47	**15.31**	11.57	3.27	**14.84**
RCPD Demand	WinDem	137	c/kW/day	3.19	30.79	**33.98**	3.12	27.65	**30.77**
Summer Day	SD33	4	c/kWh	1.35	0.00	**1.35**	0.43	0.00	**0.43**
Summer Night	SN33	4	c/kWh	0.71	0.00	**0.71**	0.24	0.00	**0.24**
Winter Day	WD33	4	c/kWh	3.63	0.00	**3.63**	0.77	0.00	**0.77**
Winter Night	WN33	4	c/kWh	0.71	0.00	**0.71**	0.24	0.00	**0.24**
Category 3.4									
Anytime Demand	AnyDem34	127	c/kVA/day	12.63	3.47	**16.10**	12.35	3.27	**15.62**
RCPD Demand	WinDem	137	c/kW/day	3.19	30.79	**33.98**	3.12	27.65	**30.77**
Summer Day	SD34	127	c/kWh	1.35	0.00	**1.35**	1.33	0.00	**1.33**
Summer Night	SN34	127	c/kWh	0.71	0.00	**0.71**	0.70	0.00	**0.70**
Winter Day	WD34	127	c/kWh	3.63	0.00	**3.63**	3.57	0.00	**3.57**
Winter Night	WN34	127	c/kWh	0.71	0.00	**0.71**	0.70	0.00	**0.70**
Category 3.5									
Anytime Demand	AnyDem35	2	c/kVA/day	11.84	3.47	**15.31**	11.57	3.27	**14.84**
RCPD Demand	WinDem	137	c/kW/day	3.19	30.79	**33.98**	3.12	27.65	**30.77**
Summer Day	SD35	2	c/kWh	0.91	0.00	**0.91**	1.33	0.00	**1.33**
Summer Night	SN35	2	c/kWh	0.57	0.00	**0.57**	0.70	0.00	**0.70**
Winter Day	WD35	2	c/kWh	3.10	0.00	**3.10**	3.57	0.00	**3.57**
Winter Night	WN35	2	c/kWh	0.57	0.00	**0.57**	0.70	0.00	**0.70**
Power Factor Charge (where applies)									
All Group 3 Categories	kVAr	3	c/kVAr/day	25.45	0.00	**25.45**	25.05	0.00	**25.05**
Large Category fixed charge only1									
Cat 6.1		1		218,286	1,847,123	**2,065,409**	213,378	1,792,841	**2,006,219.00**
Cat 6.2		1		233,950	313,138	**547,088**	228,690	315,613	**544,302.53**

Notes

Prices apply for all GXPs/Regions for each Group/Category
LFC = Low User Fixed Charge for less than 8,000 kWh consumption pa
Day: 0700 to 2300
Night: 2300 to 0700
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

Electricity Information Disclosure Determination 2012

Section 2.4.3 (8) : Proportion of Target Revenue collected through each pricing component

Price/Tariff Description	Code	No of ICPs	Proportion of Total Revenue		
			Transmission	Distribution	Total
Group 0 (unmetered)					
Low capacity - Electric fences, Comms etc	0UNM	99	0.24%	0.49%	0.74%
Streetlight only connection	0S	26	0.00%	0.00%	0.00%
Temporary box	0TBS	121	0.02%	0.03%	0.05%
Streetlight attached	0STL	163	0.05%	0.09%	0.14%
Metered supplies, 15-150 kVA Capacity					
Group 1 15kVA capacity					
Daily Charge	1	34,504	0.96%	3.62%	4.58%
Anytime Continuous	1ANY	33,495	12.83%	25.78%	38.60%
Day (of Day/Night)	1DAY	304	0.13%	0.26%	0.39%
Night	1NIT	1,752	0.03%	0.07%	0.10%
Off Peak Controlled	1OPK	119	0.12%	0.24%	0.36%
Controlled Water	1WSR	25,406	2.09%	4.30%	6.39%
Group 2 20-150 kVA					
Capacity (Except domestic low users)	2	2,596	1.60%	3.56%	5.15%
Anytime Continuous	2ANY	2,160	3.69%	9.74%	13.43%
Day (of Day/Night)	2DAY	451	1.07%	2.79%	3.86%
Night	2NIT	501	0.02%	0.05%	0.06%
Off Peak Controlled	2OPK	60	0.14%	0.37%	0.51%
Controlled Water	2WSR	672	0.10%	0.26%	0.36%
Group 2 Domestic LFC, < 40kVA capacity					
Group 2 Domestic low users < 40kVA.	2LLFC	17	0.00%	0.00%	0.00%
Anytime Continuous	2LANY	14	0.01%	0.01%	0.02%
Day (of Day/Night)	2LDAY	2	0.00%	0.00%	0.00%
Night	2LNIT	2	0.00%	0.00%	0.00%
Off Peak Controlled	2LOPK	0	0.00%	0.00%	0.00%
Controlled Water	2LWSR	8	0.00%	0.00%	0.00%
Group 2 Domestic LFC, ≥ 40kVA capacity					
Group 2 Domestic low users ≥ 40kVA	2HLFC	1	0.00%	0.00%	0.00%
Anytime Continuous	2HANY	1	0.00%	0.00%	0.00%
Day (of Day/Night)	2HDAY	0	0.00%	0.00%	0.00%
Night	2HNIT	0	0.00%	0.00%	0.00%
Off Peak Controlled	2HOPK	0	0.00%	0.00%	0.00%
Controlled Water	2HWSR	0	0.00%	0.00%	0.00%
Group HLF (15 - 150kVA)					
Capacity Charge	HLF	41	0.23%	0.80%	1.02%
Anytime Continuous	HLFANY	28	0.06%	0.15%	0.20%
Day (of Day/Night)	HLFDAY	14	0.05%	0.13%	0.18%
Night	HLFNIT	14	0.00%	0.00%	0.00%
Off Peak Controlled	HLFOPK	0	0.01%	0.01%	0.02%
Controlled Water	HLFWSR	7	0.00%	0.00%	0.00%
Generation (all groups/categories)	GENA	60			
GROUP 3. TOU metered, ≥150 kVA					
Category 3.1					
Anytime Demand	AnyDem31	4	0.07%	0.19%	0.27%
RCPD Demand (incl all other G3 categories)	WinDem	129	5.05%	0.52%	5.57%
Summer Day	SD31	4	0.00%	0.05%	0.05%
Summer Night	SN31	4	0.00%	0.01%	0.01%
Winter Day	WD31	4	0.00%	0.06%	0.06%
Winter Night	WN31	4	0.00%	0.01%	0.01%
Category 3.3					
Anytime Demand	AnyDem33	4	0.04%	0.14%	0.18%
RCPD Demand	WinDem	129			
Summer Day	SD33	4	0.00%	0.13%	0.13%
Summer Night	SN33	4	0.00%	0.03%	0.03%
Winter Day	WD33	4	0.00%	0.16%	0.16%
Winter Night	WN33	4	0.00%	0.01%	0.01%
Category 3.4					
Anytime Demand	AnyDem34	119	1.14%	4.16%	5.31%
RCPD Demand	WinDem	129			
Summer Day	SD34	119	0.00%	1.35%	1.35%
Summer Night	SN34	119	0.00%	0.25%	0.25%
Winter Day	WD34	119	0.00%	2.85%	2.85%
Winter Night	WN34	119	0.00%	0.20%	0.20%
Category 3.5					
Anytime Demand	AnyDem35	2	0.13%	0.43%	0.56%
RCPD Demand	WinDem	129			
Summer Day	SD35	2	0.00%	0.13%	0.13%
Summer Night	SN35	2	0.00%	0.04%	0.04%
Winter Day	WD35	2	0.00%	0.34%	0.34%
Winter Night	WN35	2	0.00%	0.03%	0.03%
Power Factor Charge (where applies)					
All Group 3 Categories	kVAr	2	0.00%	0.01%	0.01%
Large Category fixed charge only					
Cat 6.1	Excl Irr	1	4.43%	0.52%	4.95%
Cat 6.2		1	0.75%	0.56%	1.31%
All pricing			**35.05%**	**64.95%**	**100.00%**

Network Tasman Limited
52 Main Road Hope
PO Box 3005
Richmond 7050
Nelson, New Zealand
Tel: 64-03-989-3600
Toll-free: 0800 508 098
Fax: 64-3-989-3631
E-mail: info@networktasman.co,nz
Website: www.networktasman.co.nz

11 March 2014

Director - Networks Branch
Commerce Commission
PO Box 2351
The Terrace
Wellington

Dear Sir or Madam

Disclosure of Pricing and Pricing Methodology 2014-15

Pursuant to the Electricity Distribution Information Disclosure Determination 2012 Clause 2.4.1, please find attached a copy of Network Tasman Limited's line pricing and line pricing methodology and information concerning line business costs to be recovered by line charges for the 2014-15 financial year.

This information has been publicly disclosed on the company's web site and directors' statutory declarations are also attached.

Should you have any queries concerning this information please do not hesitate to contact me on DDI (03) 989 3615.

Yours sincerely
NETWORK TASMAN LIMITED

S W Mackey
Chief Executive Officer

Enclosures

NetworkTasman

Network Tasman Limited

52 Main Road Hope
PO Box 3005
Richmond 7050
Nelson, New Zealand

Tel: 64-03-989-3600
Toll-free: 0800 508 098
Fax: 64-3-989-3631
E-mail: 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, John McCliskie and Christopher Turner 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.

C Turner ______________________ Date 11 March 2014

______________________ Date 12 March 2014

