

# networktasman

Your consumer-owned electricity distributor

**Network Tasman Limited**

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

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Email: [info@networktasman.co.nz](mailto:info@networktasman.co.nz)

Website: [www.networktasman.co.nz](http://www.networktasman.co.nz)

5 April 2012

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

Dear Sir

**Disclosure of Pricing And Pricing Methodology 2012-13**

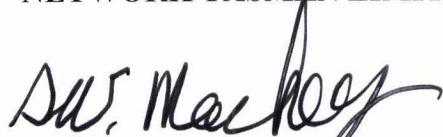
Pursuant to the Electricity Information Disclosure Requirements issued 31 March 2004 (Consolidating all amendments to 31 October 2008), Part 5 Clause 22 & 23, please find attached a copy of Network Tasman Limited's line pricing, line pricing methodology and information concerning line business costs to be recovered by line charges for the 2012-13 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*

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**IN ACCORDANCE WITH THE COMMERCE ACT  
(ELECTRICITY INFORMATION DISCLOSURE REQUIREMENTS 2004).**

Requirement 36(I)

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**STATUTORY DECLARATION IN RESPECT OF STATEMENTS AND  
INFORMATION SUPPLIED TO THE COMMERCE COMMISSION**

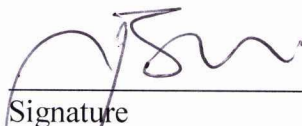
I, Christopher IM Turner, of Hill Street, Richmond, being a director of Network Tasman Limited, solemnly and sincerely declare that having made all reasonable enquiry, to the best of my knowledge, the information attached to this declaration is a true copy of the information made available to the public by Network Tasman Limited under the Commerce Commission's Electricity Information Disclosure Requirements 2004.

And I make this solemn declaration conscientiously believing the same to be true and by virtue of the Oaths and Declarations Act 1957.

Declared at this 5<sup>th</sup> day of April 2012



CIM Turner

  
Signature

Anissa Bain  
Lawyer  
Pitt & Moore  
Richmond

Justice of the Peace (*or* Solicitor *or* other person authorised to take a statutory declaration)

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## NETWORK TASMAN LIMITED

### Pursuant to Electricity Information Disclosure Requirements 2004

#### Part 6. Disclosure of Line Charges.

27. Disclosure of new line charges payable by 5 or more consumers

28. Disclosure of new line charges for other consumers

#### Group Zero

		Prices from 01 April 2012			Prices prior to 01 April 2012		
Daily Charge All areas	Number of Consumers	Local Line	National Line	Total	Local Line	National Line	Total
Temporary Boxes cents/day	76	88.00	33.00	<b>121.00</b>	85.00	31.00	<b>116.00</b>
Phone Booths, PCM cabinets, Electric fences etc cents/day	98	33.00	14.00	<b>47.00</b>	32.00	13.00	<b>45.00</b>
Street Lights cents/watt/day	153	0.076	0.028	<b>0.104</b>	0.074	0.026	<b>0.100</b>

#### Group One and Group Two.

Group 1 consumers take standard supply with fusing limiting maximum demand to less than 15kVA.

Group 2 consumers take supplies with a maximum demand capacity limited to between 15 & 150 kVA.

Unit Prices							
		Prices from 01 April 2012			Pricing prior to 01 April 2012		
Tariff	Number of Consumers	Local Line	National Line	Total	Local Line	National Line	Total
		c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh
Anytime	35,307	5.95	2.27	<b>8.22</b>	5.76	2.14	<b>7.90</b>
Day (of Day/Night)	708	6.54	2.50	<b>9.04</b>	6.33	2.36	<b>8.69</b>
Controlled Water	26,077	2.76	1.03	<b>3.79</b>	2.67	0.97	<b>3.64</b>
Night	2,952	1.97	0.77	<b>2.74</b>	1.91	0.73	<b>2.64</b>
Off Peak	156	4.67	1.73	<b>6.40</b>	4.52	1.63	<b>6.15</b>
<b>Group 1 Daily Charges</b>							
	Number of Consumers	Local Line	National Line	Total	Local Line	National Line	Total
		¢/day	¢/day	¢/day	¢/day	¢/day	¢/day
All areas	34,122	11.85	3.15	15.00	11.85	3.15	15.00
<b>Group 2 Demand Charges</b>							
	Number of Consumers	Local Line	National Line	Total	Local Line	National Line	Total
All areas: cents/kVA/day	2,592	3.26	0.87	<b>4.13</b>	3.20	0.85	<b>4.05</b>

All prices exclude GST.



## NETWORK TASMAN

**Low User Group Two.** This is a low-user pricing option for Group Two domestic customers that has a low fixed charge and higher variable charges.

		Prices <u>from</u> 01 April 2012			Prices <u>prior</u> to 01 April 2012		
Capacity of 20 kVA or 30 kVA	Number of Consumers	Local Line	National Line	Total	Local Line	National Line	Total
Variable Charge		c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh
Anytime	14	9.05	2.27	<b>11.32</b>	8.76	2.14	<b>10.90</b>
Day (of Day/Night)	2	9.64	2.50	<b>12.14</b>	9.33	2.36	<b>11.69</b>
Controlled Water	8	5.86	1.03	<b>6.89</b>	5.67	0.97	<b>6.64</b>
Night	2	5.07	0.77	<b>5.84</b>	4.91	0.73	<b>5.64</b>
Off Peak	0	7.77	1.73	<b>9.50</b>	7.52	1.63	<b>9.15</b>

Capacity 40 kVA or more	Number of Consumers	Local Line	National Line	Total	Local Line	National Line	Total
Variable Charge		c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh
Anytime	1	12.80	2.27	<b>15.07</b>	12.46	2.14	<b>14.60</b>
Day (of Day/Night)	0	13.39	2.50	<b>15.89</b>	13.03	2.36	<b>15.39</b>
Controlled Water	0	9.61	1.03	<b>10.64</b>	9.37	0.97	<b>10.34</b>
Night	0	8.82	0.77	<b>9.59</b>	8.61	0.73	<b>9.34</b>
Off Peak	0	11.52	1.73	<b>13.25</b>	11.22	1.63	<b>12.85</b>

Fixed Charge cents per day all areas	Number of Consumers	Local Line	National Line	Total	Local Line	National Line	Total
Capacity of 20 kVA or 30 kVA	16	11.85	3.15	15.00	11.85	3.15	15.00
Capacity 40 kVA or more	1	11.85	3.15	15.00	11.85	3.15	15.00

### High Load Factor - Groups 1&2

This pricing option is offered for first time from 1 April 2012 to those Group 1&2 consumers who have high annual kWh consumption relative to their network fuse capacity (kVA).

HLFC		Prices <u>from</u> 01 April 2012			Prices <u>prior</u> to 01 April 2012		
All areas	Number of Consumers	Local Line	National Line	Total	Local Line	National Line	Total
<b>Tariff cents/ kWh</b>		c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh
Anytime	0	1.61	0.61	<b>2.22</b>	N/A	N/A	N/A
Day (of Day/Night)	0	1.75	0.67	<b>2.42</b>	N/A	N/A	N/A
Controlled Water	0	0.73	0.27	<b>1.00</b>	N/A	N/A	N/A
Night	0	0.50	0.20	<b>0.70</b>	N/A	N/A	N/A
Off Peak	0	1.26	0.47	<b>1.73</b>	N/A	N/A	N/A
<b>HLF Demand Charge</b>							
Cents/kVA/day	0	29.87	7.94	<b>37.81</b>	N/A	N/A	N/A

All prices exclude GST



# NETWORK TASMAN

## Group Three and Six.

NETWORK TASMAN LINE CHARGE DISCLOSURE PRICING <i>from</i> 01 April 2012													
NETWORK TASMAN DISTRIBUTION (ex GST)													
		Unit Charges c/kWh				Demand Charges			TRANS POWER (ex GST)				
		Summer		Winter		Anytime c/kVA/day	RCPD c/kW/day	Summer c/kWh		Winter c/kWh		Demand Charges	
		Day	Night	Day	Night			Day	Night	Day	Night	Anytime c/kVA/day	RCPD c/kW/day
Consumers Group 3	No												
Category 1	4	0.42	0.24	0.76	0.24	8.46	3.06	0.0	0.0	0.0	0.0	2.44	24.02
Category 3	4	1.31	0.69	3.52	0.69	11.37	3.06	0.0	0.0	0.0	0.0	2.44	24.02
Category 4	119	1.31	0.69	3.52	0.69	12.13	3.06	0.0	0.0	0.0	0.0	2.44	24.02
Category 5	2	0.89	0.56	3.00	0.56	11.37	3.06	0.0	0.0	0.0	0.0	2.44	24.02
Total Group 3	129												
Group 6	No												
Category 6.1	1	Annual fixed charged billed monthly											
Category 6.2	1	Annual fixed charged billed monthly											
Total Group 6	2												
Embedded Network Customer													
Category 1	1	Annual fixed charged billed monthly											

# NETWORK TASMAN

Group Three and Six.

NETWORK TASMAN LINE CHARGE DISCLOSURE PRICING <i>prior</i> 01 April 2012													
NETWORK TASMAN DISTRIBUTION (ex GST)													
				Unit Charges c/kWh				Demand Charges		TRANS POWER (ex GST)			
										Unit Charges c/kWh			
				Summer Day	Summer Night	Winter Day	Winter Night	Anytime	Winter	Summer Day	Summer Night	Winter Day	Winter Night
Consumers	No												
Group 3													
Category 1	4			0.40	0.23	0.73	0.23	8.16	3.03	0.0	0.0	0.0	
Category 3	4			1.28	0.67	3.43	0.67	11.09	3.03	0.0	0.0	0.0	2.02
Category 4	119			1.28	0.67	3.43	0.67	11.83	3.03	0.0	0.0	0.0	2.02
Category 5	2			0.87	0.54	2.93	0.54	11.09	3.03	0.0	0.0	0.0	2.02
Total Group 3	129												19.69
Group 6	No												
Category 1	1			Annual fixed charged billed monthly				\$204,491		Annual charge billed monthly			\$1,527,672
Category 2	1			Annual fixed charged billed monthly				\$219,167		Annual charge billed monthly			plus share of any associated Common Quality Charges and Rebates \$252,594
Total Group 6	2												plus share of any associated Common Quality Charges and Rebates
Embedded Network Customer													
Category 1	1			Annual fixed charged billed monthly				\$2,040 plus utilised %age R&M		Annual charge billed monthly			\$2,496,043
													plus share of any associated Common Quality Charges and Rebates

All prices exclude GST.



# **NetworkTasman**

## **PRICING METHODOLOGY DISCLOSURE**

**For Year Commencing 1 April 2012**

**Pursuant to**

**Electricity Information Disclosure Requirements**

**Issued 31 March 2004**

**(Consolidating all amendments to 31 October 2008)**

**For compliance with :**

**Requirement 22: Disclosure of Pricing Methodology**

**Requirement 23: Contents of Pricing Methodology Disclosures**

**Network Tasman Limited**

**P O Box 3005**

**RICHMOND 7050**



## 1.0 REGULATORY REQUIREMENT

- 1.1 The Information Disclosure Requirements 2004 (Sections 22 & 23) gazetted by the NZ Commerce Commission require electricity line businesses to annually disclose:
  - The pricing methodology used to calculate line prices
  - key components of 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 revenues amongst consumer groups
  - the method by which the line owner determines the proportion of fixed and variable charges.
- 1.2 The Electricity Authority has also published Distribution Pricing Principles and Information Disclosure Guidelines (February 2010) in which it promotes a principles based approach to on EDB line pricing and associated information disclosures. The Authority has developed these guidelines to be consistent with the Information Disclosure Requirements 2004.

## 2.0 FINANCIAL INFORMATION

- 2.1 This pricing disclosure relies on financial information drawn from NTL's line business budget and financial forecasts for the year ending 31 March 2013. Line business costs have been separated from NTL's other non line business activities in a manner consistent with the Electricity Information Disclosure Handbook 2004 (as amended to 31 October 2008).
- 2.2 The forecast financial information provides the transmission, operating, maintenance, depreciation and overhead cost data used to determine NTL's line business annual revenue requirement.
- 2.3 Network capital costs are calculated using NTL's estimate of WACC and the Regulatory Asset Base (RAB) forecasts for Information Disclosure as at 31 March 2012.

The RAB is based on the 2004 ODV of systems fixed assets and this is rolled forward to 31 March 2012 using the methodology inherent in the Information Disclosure Regulations. The roll forward includes actual capital expenditure at cost and depreciation at ODV standard rates for the intervening period to 31 March 2012.

## 3.0 NETWORK TASMAN PRICING PRINCIPLES

- 3.1 NTL's pricing methodology reflects, to the extent possible:
  - The pricing principles stated in NTL's Statement of Corporate Intent, 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.
- 3.2 The following pricing objectives are stated in NTL's SCI (available on website) and are incorporated in Use of Systems Agreements with retailers:
  - A fair and reasonable rate of return to shareholders (cost of capital measured on a pre-tax, pre discount basis) will be recovered

- This cost of capital will be reasonably allocated to, and recovered from, each consumer group
- 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 level of uniformity amongst like consumers and across 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.

- 3.3 The specific pricing principles published in Electricity Authority Guidelines are stated in Section 21 and are also viewable at:

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

- 3.4 Where pricing objectives or principles are in conflict, Network Tasman Directors exercise their discretion and judgement to set an acceptable trade-off between conflicting items.

#### **4.0 LINE CHARGE DERIVATION**

- 4.1 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.

#### **5.0 PRICING FOR DISTRIBUTION SERVICES**

- 5.1 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

#### **6.0 NTL DISTRIBUTION REVENUE REQUIREMENT**

- 6.1 The Distribution Revenue Requirement for a the local network is the sum of:
- operating & maintenance costs
  - overhead costs
  - return *of* capital employed (depreciation)
  - return *on* capital employed (WACC)
- 6.2 Network Tasman Ltd's distribution costs are accumulated into the following classifications:



- Direct Network Costs which include operations and maintenance costs and any direct overheads
  - Indirect Network Costs which include indirect overheads and administration costs
  - Depreciation (return of capital) which is based on ODV standard lives for systems assets and financial reporting rates for non systems assets
  - Capital Costs (return on capital/assets employed) which is calculated by applying WACC to NTL's RAB
- 6.3 The sum of the costs above equates to the line business's total Distribution Revenue Requirement. Information on NTL's 2012-13 Distribution Revenue Requirement by cost classification and load group is provided in Appendix A.
- 6.4 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 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.
- 6.5 The cost of capital (WACC) is derived using the Capital Asset Pricing Model. For the financial year commencing 1 April 2012 NTL used the following inputs:
- 5 year government stock rate to estimate the risk free rate at 3.8%
  - Target capital structure of 40% debt to total assets
  - Cost of debt 5.8%
  - Asset beta of 0.40 as the measure of the line business systematic risk
  - post tax market risk premium for equity of 7.0%
  - corporate tax rate of 28.0%
- Based on these inputs NTL has calculated a pre tax cost of capital of 8.6% or a post-tax WACC of 6.2% for NTL's line business assets.

## 7.0 LOAD GROUPS

- 7.1 NTL's Distribution Revenue Requirement is allocated to consumer load groups and distribution charges are derived for ICP's (Installation Control Points) within those consumer load groups.
- 7.2 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 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 and usually 33kV and have 11kV metering.

- 7.3 Government policy and SCI requirements guide Network Tasman to treat loads on rural spurs lines largely the same as those on the urban meshed parts of the network. Consequently load groups, and therefore distribution charges, are not differentiated across the various geographical areas serviced by the network.
- 7.4 Load group statistics used to allocate costs and calculate prices are provided in Appendix A.

## 8.0 ALLOCATION OF NETWORK COSTS TO LOAD GROUPS

### 8.1 Direct Network Costs, Systems Depreciation and Capital Costs

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

- 8.2 These network costs are then accumulated into those associated with the upper & lower segments of the network as shown in Figure 3.2.
- 8.3 Using the Figure 3.3 formulae, the network costs accumulated to the upper 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.
- 8.4 A key difference between the treatment of the upper and lower network cost components is that
- no lower network costs are allocated 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
<b>TOTALS</b>	<b>a</b>	<b>b</b>	<b>r</b>	<b>C</b>

**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
<b>TOTALS</b>	<b>C</b>	<b>D</b>	<b>E</b>

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

**FIGURE 3.3 ALLOCATION OF DIRECT NETWORK COSTS TO LOAD GROUPS**

Load Group	Supply Voltage V	Coincident Demand MVA	Accumulated Formula MVA	Cost Allocation Formula	Total Direct Cost Allocation By Group
(1) 400V Gen ≤ 15 kVA	230/400	M1	A1	$(M1/A6 \cdot D) + (M1' / A3 \cdot E)$	TDC 1
(2) 400V Gen >15 & <150kVA	400	M2	A2	$(M2/A6 \cdot D) + (M2' / A3 \cdot E)$	TDC 2
(3) 400V & 11kV > 150 kVA	400/11,000	M3	A3	$(M3/A6 \cdot D) + (M3' / A3 \cdot E)$	TDC 3
(6) Ded. Network	Over 11,000	M6	A6	$(M6/A6 \cdot Dd)$	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

### 8.5 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).

**FIGURE 3.4 LOAD GROUP REVENUE REQUIREMENT**

Load Group	Supply Voltage	Total Direct Cost Allocation	Total General Overhead Allocation	Total Distribution Revenue Requirement
(1) 400V Gen ≤ 15 kVA	230/400	TDC 1	OH1	TR1 = TDC 1+OH1
(2) 400V Gen > 15 & < 150 kVA	400	TDC 2	OH2	TR2 = TDC 2+OH2
(3) 400V & 11kV > 150 kVA	400/11,000	TDC 3	OH3	TR3 = TDC 3+OH3
(6) Ded. Network	Over 11,000	TDC 6	OH6	TR6 = TDC 6+OH6



## 9.0 DERIVATION OF DISTRIBUTION TARIFFS.

### 9.1 General

The TRi 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).

### 9.2 Determining the proportions of fixed and variable tariffs

In determining the proportions of revenue raised by fixed and variable tariffs NTL must strike a balance between the conflicting demands arising from:

- 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 theory encourages the application of cost reflective pricing. Regionally differentiated pricing with a strong peak demand / capacity based elements (kVA) would be the logical result. This supports economic efficiency by reflecting
- the fixed and sunk nature of line business cost structures and assets
  - the new investment costs caused by demands for capacity at peak times.
- The government owned grid operator Transpower operates a pricing methodology reflecting this rationale.
- (b) Government policy and regulations compel ELBs to:
- offer a 15 cents/day fixed charge tariff option to all domestic consumers with consumption is 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.

Consequently they generally prefer kWh based charges and fixed daily charges.

- (d) NTL acknowledges consumers have 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 consumers can exert a greater level of influence over their electricity bills.
  - higher use business consumers generally consider capacity based charging that properly and fairly reflects costs of supply and rewards high load factor consumers for efficient use of network assets.
- (e) To achieve a compromise between the conflicting demands above 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.



- Group 2 tends to have mostly business sector consumers with above average load factors and so greater reliance is placed on capacity based pricing using installed network fuse sizes.
- 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.
- Group 6 consumers have fully fixed charges reflecting the high levels of asset dedication; they essentially pay an annual fixed rental for the dedicated assets used in 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 cost of supply to those areas.
- There is no tariff differentiation (fixed or variable) based on consumers end use of electricity (i.e. between business or domestic).

### 9.3 Fixed and Capacity based Tariffs

- (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) on Transpower's transmission system in the Upper South Island.

### 9.4 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 tariffs, depending on the time of use profile or the level and type of load interruptability / restrictions the consumer commits to in advance.

### 9.5 Revenue Adequacy

- (a) The distribution revenue requirement for each group, (TR1 to TR6 in Figure 3.4) may exceed what that group is currently paying. 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 customer groups where connection density is low and where load factor is poor.
- (b) Consequently Network Tasman has a choice of seeking a Customised Price Pathway or accepting a shortfall of actual distribution revenue over the total revenue requirement. To date NTL has accepted the latter.
- (c) Under recovery of distribution revenue from one particular customer group is not normally made good by over recovery from any of the other groups.

## 10.0 DISTRIBUTION PRICES - Group 1

- 10.1 Group 1 distribution revenue requirement TR1 is split between that part to be recovered by a fixed charge (FC1), and that part to be recovered by a variable charge (VC1).
- 10.2 The total annual fixed charge for Group 1 ICP's is set at \$55pa. or 15 cents/day. The distribution component of this fixed charge, FC1, is \$43.25 and is recovered from all consumers (ICPs) with no account being taken of geographical area or whether use is business or residential. This approach automatically establishes the proportion of revenue recoverable from fixed charges and has been adopted to:
- meet Government low user regulatory requirements
  - avoid unwarranted discrimination between small business and small residential consumers
  - minimise the additional transaction and administration costs NTL and electricity retailers face if a separate optional lower user tariff was offered.
  - minimise the level of irrecoverable revenue leakage under regulatory price path formulas if an optional low user tariff had been offered part way through a control period.
- 10.3 The total variable charge VC1 recovers the residual revenue from TR1 and is combined with VC2 from Group 2 and variable tariffs are set for both load groups at common levels. This promotes simplicity and lowers both NTL's and retailers' transaction costs.
- 10.4 Variable tariff rates are determined by dividing the number of units consumed by Group 1 and 2 into VC1+VC2 and applying a set of relative weightings between the tariff types on offer.
- 10.5 The relative weights are in part driven by legacy issues but they 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" and to 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 : 2012-13 Budget Data :

TR1 budgeted 2012-13	=	\$13,432,000
Number of G1 ICPs (forecast)	=	34,318
Total to be recoverable by fixed charges		
Fixed charge per annum	=	\$43.25 pa or 11.85 cents /day
	=	34,318*\$43.25
FC1	=	\$1,484,000
Total Variable Charge VC1		
	=	\$13,432,000 - \$1,484,000
	=	\$11,948,000 & accumulated with Group 2 VC2 for recovery



## 11.0 DISTRIBUTION PRICES - Group 2

- 11.1 Group 2 distribution revenue requirement TR2 is split between that to be recovered by a fixed capacity charge (FC2), and that to be recovered by a variable charge (VC2).
- 11.2 Each ICP in Group 2 has an Anytime Maximum Demand (AMD between 20 and 150 kVA) based on installed supply fuse sizes.
- 11.3 Group 2 Fixed charge revenue is targeted at 20% of TR2 or at approximately twice the level for Group 1. This ensures that fixed charges step up materially for consumers wishing to :
- move between Group 1 and Group 2
  - upgrade their installed fuse size within the kVA bands on offer in Group 2.
- Consumers are provided with a clear signal to minimise their peak capacity demands and to use scarce network capacity efficiently.
- 11.4 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.
- 11.5 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.
- 11.6 The total variable charge (VC2) recovers the residual revenue of TR2 and is combined with VC1 to be recovered using common tariff rates as described above in 10.3-10.5.

### Load Group 2 profile from 2012-13 budget data:

Consumer	AMD (kVA)
x	40
y	70
z	110

.....  
Total Group 2 117,600 kVA

Group 2 TR2 Budget 2012-13	\$7,234,000
Total Fixed Charge FC2 ~ 20%	\$1,400,000
Total Variable Charge VC2 ~80%	\$5,834,000 added to VC1 from Group 1 for recovery
Capacity Tariff	= \$1,400,000 / 117,600
	= \$11.90 per kVA pa.
Consumer "x" AMD Charge / day	= (11.90 * 40) / 365
	= \$1.30 per day

### Group 1 & 2 Variable Tariffs

Total \$ to be recovered from variable charges for Group1	
VC1	= \$13,432,000 – \$1,484,000
	= \$11,948,000
Total \$ to be recovered from variable charges from Group 2	
VC2	= \$7,234,000 - \$1,400,00
	= \$5,835,000
Combined Group1&2 amount to be recovered from variable tariffs	
VC1+VC2	= \$11,948,000+\$5,835,000
	= \$17,780,000



Tariff s <u>Common to G1&amp; G2</u>	Allocated <u>Weightings</u>	G1+G2 <u>Budgeted Units</u>
A - Anytime	100%	240 GWh
B - Day	110%	21 GWh
C - Controlled Water	46%	67 GWh
D - Night	33%	14 GWh
Line Charge Tariff A	=	$\$17,780,000 / (240*1.0 + 21*1.10 + 67*0.46 + 14*0.33)$
	=	5.95 cents per kWh of A metered consumption
Line Charge Tariff B	=	$\$0.0595 * 1.10$
	=	6.54 cents per kWh of B metered consumption
Line Charge Tariff C	=	$\$0.0595 * 0.46$
	=	2.76 cents per kWh of C metered consumption
Line Charge Tariff D	=	$\$0.0595 * 0.33$
	=	1.97 cents per kWh of D metered consumption

11.7 **Group 2 Low User Tariff (2LFC):** Because there are a number of domestic customers in Group 2, NTL is required by regulation 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 option 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.

11.8 **High Load Factor Tariff (HLFC):** From 1 April 2012 NTL will offer a pricing option suitable for mass market customers with high load factors. The tariff has been introduced to offset one of the consequences of the variable (kWh) component of NTL standard mass market tariffs being higher than desirable. This situation has come about by NTL adopting the 15 cents per day low user fixed charge for all Group 1 consumers in order to achieve the fairest, simplest and most cost effective means of complying with the low user regulations. The consequential loss of fixed revenue was 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 per kVA supply charge. The HLF pricing is beneficial to mass market customers with load factors in excess of about 28%; which is about 7% or around 200 Group 1&2 consumers. The HLF tariff also provides a smoother transition for these consumers where they move up to Group 3 pricing.

## 12.0 DISTRIBUTION PRICES - Group 3.

12.1 Group 3 distribution revenue requirement TR3 is split between that part recoverable by a capacity charges (FC3) and that recoverable by a variable charge (VC3).

12.2 Group 3 customers are primarily larger, high load factor business consumers and so the fixed or capacity based charges for this group are set to recover approximately 50% of TR3. This provides strong signals to minimise anytime and winter peak demand levels and rewards good load factor much more than is the case in Groups 1&2.

- 12.3 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 that consumers kW load coincident with Transpower's 12 peak loads on USI grid for the year ending 31<sup>st</sup> 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.
- 12.4 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 passing through Transpower Interconnection charges. This gives a dollar per AMD kVA and a dollar per Winter RCPD kW as distribution tariffs .
- 12.5 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.
- 12.6 The total variable charge (VC3) recovers the residual revenue from TR3 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.

**Load Group 3: Category 3.4 2012-13 Budget Data :**

<u>Consumer</u>	<u>AMD</u>	<u>Winter RCPD</u>
x	225	200
y	194	120
Group Total	36,918	15,000
Total Group 3 Dist Revenue - TR3	\$3,744,000	
Fixed Charge recovery % approx.	48.0%	
Total Demand Based Revenue - FC3	\$1,802,000	
Total Variable Charge Revenue-VC3	\$1,940,000	
Anytime % of demand/fixed approx	91%	
AMD Tariff	=	(\$1,802,000 * 0.907)/36,918
	=	\$44.28 per kVA
WMD Tariff	=	(\$1,802,000*0.093 )/15,000
	=	\$11.17 per kW pa.
<u>Consumer Capacity Charges</u>		
Consumer "x" Winter RCPD	=	200 * 11.17 / 12
	=	\$187 per month
Consumer "x" AMD Charge	=	225 * 44.27 / 12
	=	\$830 per month
(The Variable charge per tariff is calculated in the same manner as for Group 1&2)		

### 13.0 DISTRIBUTION PRICES - Group 6.

- 13.1 These consumers are large enough, and few enough, to warrant individual calculation of line charges based on the ODRC values and direct costs associated with the dedicated or semi-dedicated assets used in their supply. General overheads are allocated using management estimates.
- 13.2 Distribution charges are calculated as an annual fixed amount, and are billed monthly.



#### **14.0 PRICING FOR TRANSMISSION SERVICES**

- 14.1 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 overall line charges.

#### **15.0 NTL TRANSMISSION REVENUE REQUIREMENT**

- 15.1 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 (net of EVA adjustments if any)
- Interconnection charges
- New investment charges
- Loss and constraint rental rebate credits

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

#### **16.0 ALLOCATION OF TRANSMISSION COSTS LOAD GROUPS.**

- 16.1 Connection costs and new investment charges are levied at each Transpower grid exit point (GXP) supplying NTL's network. These are allocated to load groups on the basis of each group's (CMD) demand contribution coincident with the AMD of that GXP.
- 16.2 Forecast loss rental rebates are allocated to Groups 1,2&3 on the basis of forecast consumption levels and are netted off total transmission costs to be recovered from each group.
- 16.3 Interconnection charges are allocated to Groups on the basis of 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.
- 16.4 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.

#### **17.0 DERIVATION OF TRANSMISSION TARIFFS.**

- 17.1 NTL recovers transmission costs from load Groups via a separate transmission pricing schedule incorporated within overall line charges as follows:
- (a) Consumers are classified into the same load groups as used for distribution pricing (see Section 7.0)
  - (b) Transmission costs for Group 6 and Bulk Supply customers are recovered on a direct pass through basis (see Section 20.0).
  - (c) The remaining transmission costs, after Group 6 pass through, are recovered from Group's 1-3 via NTL's transmission pricing schedule.
  - (d) Groups 1-3 transmission charges are recovered on a "fixed" and "variable" basis using similar rationale to that used in distribution pricing.
  - (e) To the extent possible within regulatory pricing constraints, NTL attempts to recover Transpowers connection and new investment costs allocated to Groups

1 & 2 via fixed daily or capacity based charges and the interconnection cost allocated through variable charges.

- (f) Group 1 fixed charge is expressed as a "cents per day" charge.
- (g) Group 2 fixed charge is expressed as "dollars per anytime maximum capacity" (AMD), measured in kVA and based on customer fuse size.
- (h) Group 3 fixed capacity charges are based on TOU meter data and are expressed as:
  - (i) "dollars per kW of Winter RCPD"
  - (ii) "dollars per kVA" of AMD,.

The Winter RCPD component directly passes through Transpower's interconnection charges attributable to Group 3 consumers while the AMD component recovers grid connection costs attributable to Group 3. No variable (kWh) transmission tariffs are used to recover the transmission costs attributable to Group 3 consumers.
- (i) 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 ininterruptibility / restrictions the consumer commits to in advance.

## 18.0 TRANSMISSION PRICES – GROUPS 1 – 3 Fixed / Capacity

- 18.1 **Group 1** -The total transmission cost allocated 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.

The annual fixed charge is billed on a daily basis (annual charge per ICP / 365).

- 18.2 **Group 2** - The total transmission cost allocated to Group 2 (TT2) is split between that part to be recovered by a fixed charge (TFC2), and that part to be recovered by a variable charge (TVC2).

- 18.3 Each ICP within Group 2 has an Anytime Maximum Demand (AMD) based on connection fuse size as described in Sections 11.2-11.5 above.

- 18.4 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.

- 18.5 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.

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

- 18.7 The connection and new investment component (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.



- 18.8 The interconnection portion (TFC3b) is recovered based on individual customers demands measured coincident with the USI RCPD demand measured over the previous year (Winter RCPD). The total amount recoverable by the Winter RCPD charge (TFC3b), is divided by the total Winter RCPD kW 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 Winter RCPD to give the ICP's annual charge and is divided by 12 and billed monthly.

## 19.0 TRANSMISSION PRICES - GROUPS 1-3 Variable

- 19.1 Group 1&2 variable charge amounts are combine (TVC1+TVC2) and recovered using common variable transmission tariff rates in a similar manner to G1&2 distribution charges.
- 19.2 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. 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.
- 19.3 A relative weighting is applied to differentiate peak and non-peak variable transmission tariffs common to 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.
- 19.4 The total amount to recover by variable transmission tariffs (TVC1+TVC2) is then divided by total kWh consumption Groups 1&2, and the relative weighting between the peak and off peak tariff is applied to determine the peak and off peak rates.
- 19.5 No variable tariffs are used in Group 3 pricing to recover transmission costs.

### Transmission Cost Recovery: 2012-13 Budget data

		Total
Group 1 RCPD		40,161 kW
Group 2 RCPD		16,531 kW
Group 3 RCPD		17,505 kW
Group 6 RCPD		<u>19,856 kW</u>
RCPD at GXPs		94,052 kW
TFC1	=	\$395,000
TFC2	=	\$365,000
TVC1+TVC2	=	<u>\$6,750,000</u>
TT(1+2)	=	\$7,510,000
TT3	=	\$1,934,000
Group 1 ICPs		34,318
Group 2 AMD		117,600 kVA
Group 3 AMD		44,858 kVA
Group 3 Winter RCPD		17,505 kW
Group 6 CMD		21,690 kVA
G1 Fixed Charge	=	$\$395,000 / (34,318) / 365 * 100$
	=	3.15 cents per day
G2 Fixed Charge	=	$\$365,000 / 117,600 / 365$
	=	\$3.10 per kVA pa.

**Group 1&2 Variable Transmission Tariffs**

Tariff s	Allocated	G1+G2
<u>Common to G1&amp; G2</u>	<u>Weightings</u>	<u>Budgeted Units</u>
A - Anytime	100%	240 GWh
B - Day	110%	21 GWh
C - Controlled Water	45%	67 GWh
D - Night	34%	14 GWh

$$\begin{aligned} \text{Variable Tariff A} &= \$6,750,000 / (240*1.0 + 21* 1.10 + 67 * 0.45 + 14*0.34) \\ &= 2.27 \text{ cents per kWh of A metered consumption} \end{aligned}$$

$$\begin{aligned} \text{Variable Tariff B} &= \$0.0227 * 1.10 \\ &= 2.50 \text{ cents per kWh of B metered consumption} \end{aligned}$$

$$\begin{aligned} \text{Variable Tariff C} &= \$0.0227 * 0.45 \\ &= 0.77 \text{ cents per kWh of C metered consumption} \end{aligned}$$

$$\begin{aligned} \text{Variable Tariff D} &= \$0.0227 * 0.34 \\ &= 1.03 \text{ cents per kWh of D metered consumption} \end{aligned}$$

**Group 3**

TFC3a Connection	=	\$ 400,000
TFC3b Interconnection	=	\$1,534,000
TT3 Total	=	\$1,934,000

G3 Fixed Charges	
TFC3a Connection	= \$400,000 / 44,858
	= \$8.91 pa. per kVA of AMD or 2.44 cents / kVA/day
TFC3b Interconnection	= \$1,534,000 / 17,505
	= \$87.67 per kW of Winter RCPD/ pa. or 24.02 cents/kW/day

**20.0 TRANSMISSION PRICES - GROUP 6 & BULK SUPPLY .**

- 20.1 These consumers are large enough and few enough to have their Transpower charges individually calculated. The charges are determined on a cost reflective or "look through" basis so as to mirror the underlying Transpower charging methodology
- 20.2 Connection and new investment charges are allocated to Group 6 and Bulk supply customers in proportion to their demands co-incident with the relevant GXP's top 12 annual half hour AMD's and are billed as a monthly fixed amount.

**Group 6 Budget Data 2011-12****Connection & NIA Charge Allocation -**

For Stoke GXP :

Trans Power Connection & NIA Charges Stoke GXP	=	\$1,156,000
Chargeable AMD for Stoke GXP	=	122,273 kVA
Group 6 Consumers CMD	=	21,720 kVA
G6 Consumers Transmission Connection Charge	=	21,720/122,273 * \$1,156,000
	=	\$205,346 pa. or \$17,112 / month

- 20.3 Interconnection charges are passed through directly on the consumers demand coincident (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.
- 20.4 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.



## 21.0 DISTRIBUTION PRICING PRINCIPLES & INFORMATION DISCLOSURE GUIDELINES

21.1 The Electricity Authority has published a document “Guidelines for Distribution Pricing Principles and Information Disclosure” dated February 2010. This section evaluates NTL’s general compliance with these Guidelines.

21.2 In the following sections:

- Each of the Pricing Principles in the Guidelines is identified and
- NTL’s general compliance each of the principles is reviewed

### **Pricing Principles**

***(a) Prices are to signal the economic costs of service provision, by:***

***(i) being subsidy free (equal to or greater than incremental costs, and less than or equal to standalone costs), except where subsidies arise from compliance with legislation and/or other regulation;***

The subsidy free test is a relatively academic notion and at its limit requires a separate test for each of NTL’s 37,100 consumers. 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 likely to be quite 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 reflect pricing methodology described in this document will generally lead to pricing within the subsidy free range.

### **Standalone Test**

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 small and medium sized consumers are 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 well supported by the fact that:

- NTL pricing methodology is cost reflective by Load Group
- NTL earns less than the regulators WACC on the RAV 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 \$319m is well over twice the RAV of \$158m; data from 31 March 2011 Information Disclosures.
- TPNZ charges customers for their individual 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’s 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 substantially 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 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 ODV 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.

In the past NTL has also 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.
- 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 ensures that NTL has the ability undertake an economic assessment to ensure incremental costs are properly supported by expected future line charge revenues from the new load. Where there is a shortfall NTL may



seek a capital contribution.

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 electricity users 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 stand alone costs of supply; consequently economic efficiency is compromised.

***(ii) having regard, to the extent practicable, to the level of available service capacity; and***

NTL Group 2&3 line pricing features kW and kVA pricing components directly related to the capacity demands consumers in these groups make on the distribution network and the transmission grid.

NTL's service level (kVA) signals are moderate for Group 2 consumers but are strong for Group 3 consumers. Group 6 pricing reflects service levels demanded via charges based on the level of dedicated and semi dedicated distribution assets NTL commits to the supply of these consumers. Similarly within both Groups 3 & 6, Transpower's Interconnection Charge (a grid service capacity charge) is reflected directly through to each consumer on the basis of their capacity demands coincident with the grid's USI regional peak demand (RCPD).

Where any consumer uses available network and grid capacity inefficiently NTL reserves the right to apply a kVA based power factor correction charge on sites with non-compliant power factor (PF<0.95). In practice this has been applied to TOU metered sites to good effect with only 2 out NTL top 130 sites incurring the power factor charge.

As stated above, 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 and to mitigate the irrecoverable revenue leakage under the regulatory price pathway mechanism where both an optional low user tariff and a standard cost reflective fixed/capacity charge stand side by side. 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:

- Firstly 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 60% of domestic customers qualify for the low user tariff on NTL's network).
- Thirdly, there is a desire by consumers, retailers and 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.

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 they are relatively blunt.

Group 3 & 6 consumers all have TOU metering installed and they 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 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 stand network develop levy for new loads in uneconomic zones of the network that to reflect 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 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. NTL's line charges now account for between only 29-35% of delivered charges for most mass market consumers. From 1 April 2012 NTL's mass market consumers' (Group 1 & 2 or about 97% of NTL 37,250 ICPs) variable line tariffs rates will account for about 34% -35% of the retailers delivered tariff for "peak" kWh rates and 18%-20% for "off peak" kWh rates. Consequently NTL can only have a very muted impact on delivered prices and thus on consumer behaviour; its network pricing is relatively invisible to the consumer.

Retailers may also rebundle and alter the price relativities between network peak and off peak 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 29-35% of most consumers power bills while the generation and retail component makes up the remaining 65-71%. Line pricing signals therefore get heavily buried within retail prices and are subject to rebundling and hence provide only weak and relatively ineffective consumption signals.

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 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 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 tends to present one off opportunities for consumers to lower consumption at discrete points of time
- Solar water heating is now a reasonably viable option vis electrically heated water.

Other than for water heating most electrical consumption remains relatively inelastic however NTL remains mindful of the need to retain off peak, controlled, night and summer kWh tariff rates at substantial discounts to peak and uncontrolled rates.

Electricity demand elasticity is relatively muted for mass market consumers. Therefore the means used to spread and collect any under recovered incremental costs is not overly important especially given the network costs continue to be a declining proportion of consumers power bills. Use of fixed capacity or daily charges are probably best used as these cause minimal distortion at the mass market level. The "peak" variable tariff rates can also be used as these tend to show the lowest consumption elasticity. Encouraging use of "off peak" and "controlled" rates is important as it is beneficial for network investment efficiency.



<p><b>(c) <i>Provided that prices satisfy (a) above, prices should be responsive to the requirements and circumstances of stakeholders in order to:</i></b></p>
<p><b>(i) <i>discourage uneconomic bypass;</i></b></p> <p>Bypass may occur through alternative network assets (i.e. by overbuild of existing network) or by customers adopting alternative energy sources /substitutes.</p> <p>Network pricing can address overbuild bypass incentives by ensuring network charges remain below the standalone economic costs for alternative lines supply for particular customers or groups of customers. This matter is addressed in (a)(1) above and NTL considers its network pricing and polices discourage inefficient bypass. NTL has historically reviewed bypass opportunities for major TOU customers but the businesses cases were not supported at NTL's existing line pricing. NTL is unaware of any consumers exercising overbuild bypass choices solely in response to line charge levels.</p> <p>Bypass achieved through 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 29-35% 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 lower incentives for inefficient bypass of network assets via small /micro generation embedded "behind the meter."</p>
<p><b>(ii) <i>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</i></b></p> <p>NTL considers that for mass market consumers (97 % of NTL 37,100 ICPs) the electrical network is a "general commons" and the notion of offering price quality/trade-offs for a specific customer(s) is substantially flawed. Generally other than offering a choice of differing capacity levels to mass market consumers NTL is not normally able to offer other differentiated lines services to one consumer without offering it to all other adjacent consumers sharing the same network segments, whether they want the service or not.</p> <p>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 provided, the commercial terms and the pricing NTL has in place with these consumers.</p> <p>NTL has surveyed and consulted with Group 3&amp;6 and larger Group 2 consumers concerning price quality/trade offs as part of the thresholds price control regime operated by the Commerce Commission. The consultations generally showed 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 and concern. NTL found it difficult to isolate consumers views down to those just centred on lines performance rather than those centred on the performance of the whole delivered energy package.</p>
<p><b>(iii) <i>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.</i></b></p> <p>NTL line pricing directly or indirectly encourages consideration of distribution and transmission alternatives and innovation in the following ways:</p> <ul style="list-style-type: none"> <li>• NTL only charges embedded generators for their incremental costs of connecting to the network and passes through, in full, any demonstrable saving in transmission interconnection charges (circa \$90/kW) that embedded generators deliver provided they have TOU metering installed. Where warranted, NTL will also consider passing through any avoided distribution costs directly attributable to new embedded generation plant.</li> </ul>



- NTL pricing passes through Transpower interconnection charges (circa (\$90 / kW) directly to Group 3 & 6 consumers, based on TOU data. They can thereby gain full value from any means they may have of reducing or avoiding demand coincident with USI peak grid loads.
- NTL Group 3 pricing has a substantive capacity based AMD charge which 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 \$53/kVA pa) annual network charges.
- NTL Group 3 pricing includes a power factor charge applicable at consumer sites where power factor is 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 incentivises 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 from Group 1 to Group 2.
- NTL pricing has, for all consumers, considerably higher kWh rates on tariffs chargeable on “peak” consumption than for consumption known to be “off peak” or “controlled”. 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 distribution tariffs are mostly no more than 35% of the delivered power bill, these signals are substantially muted by energy retailers who tend to offer no, minimal 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 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 GXP or zone substations. This progressively encourages all remote new loads to minimise their new capacity demands on the distribution network 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 required. 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 establish their new connection to the existing distribution network. This policy helps NTL avoid funding uneconomic 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 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 for 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 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 10 years.
- 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)

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 under NTL's 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 34,000 out of NTL's 37,100 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 all but 23 of the 2600 Group 2 ICP's) and the chargeable capacity quantities for each Group 2 ICPs are directly available to all electricity retailers from the Registry
- There are just 5 core variable (kWh) tariff rates applicable to all but 200 of the Group 1 & 2 consumers (i.e. the 5 core tariffs are used for about 36,700 out of NTL's 37,100 ICP's)
- The regulatory requirement to make available a low user charge for all domestic consumers more than doubles the number of prices 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 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 36,900 mass market consumers
- NTL's Group 3 line charges are relatively straight forward but rely heavily on TOU data. The 123 Group 3 TOU consumers are split in categories by size with 110 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.
- NTL 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.



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

<b><u>Information Disclosure Guidelines</u></b>	
<b><i>(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.</i></b>	
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 only minor revision for the 2012-13 year.	
<b><i>(b) The pricing methodology disclosed should demonstrate:</i></b>	
<b><i>(i) how the methodology links to the pricing principles and any non-compliance;</i></b>	
The link between the pricing methodology and the Electricity Authority pricing principles has been explained in Section 20 of this document.	
<b><i>(ii) the rationale for consumer groupings and the method for determining the allocation of consumers to the consumer groupings;</i></b>	
Sections 7.0 - 7.4 explain NTL's method of allocating consumers to load groups and this applies to both distribution and transmission pricing components.	
<b><i>(iii) quantification of key components of costs and revenues;</i></b>	
See Section 6.0- 6.5 for description of distribution costs and revenue components. See Section 15.0-16.4 for description of transmission costs and revenue components. See Appendix A for NTL data on cost and revenue components.	
<b><i>(iv) an explanation of the cost allocation methodology and the rationale for the allocation to each consumer grouping;</i></b>	
See Section 8.0 – 8.5 for description of the methodology for allocation of distribution costs to consumer Load Groups. See Section 16.1 – 16.4 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 2012-13.	
<b><i>(v) an explanation of the derivation of the tariffs to be charged to each consumer group and the rationale for the tariff design; and</i></b>	
See Sections 9.0-13.2 for description of distribution tariff components & derivation. See Sections 17.0-19.9 for description of transmission tariff components & derivation. See Appendix A for NTL tariff data for 2012-13.	
<b><i>(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.</i></b>	
<p>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.</p> <ul style="list-style-type: none"> <li>• Distributed generators are directly reward via pass through of the 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 must be dealt with on a case by case basis.</li> <li>• Group 6 consumers obtain full benefit from any reduction in RCPD coincident demands with respect to Interconnection Charges directly passed through by NTL.</li> <li>• 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.</li> </ul>	

- 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 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% lower than they would have otherwise been as a result of historical uptake of controlled tariff options by consumers.

***(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***

The only material change made to NTL's pricing methodology for the year commencing 1 April 2013 is the introduction of the High Load Factor pricing option for mass market customers. This is described in Section 11.8.



## Appendix A

# NetworkTasman

## THE ELECTRICITY DISCLOSURE REQUIREMENTS 2004

### REQUIREMENTS 22 & 23

- Requirement 22 Disclosure of Pricing Methodologies
- Requirement 23 Contents of Pricing Methodologies

## LOAD GROUP STATISTICS USED IN PRICING METHODOLOGY

For year commencing 1 April 2012

Customer Group	Number of ICP's	Coincident Maximum Demand (1)	Anytime Maximum Capacity	Winter Maximum RCPD	Consumption Peak	Consumption Off Peak	Total Consumption
	#	kW	kVA	kW	kWh	kWh	kWh
Group 1	34,318	52,517	514,770	40,161	171,148,087	66,896,661	238,044,748
Group 2	2,629	23,863	117,553	16,531	86,879,424	12,138,916	99,018,340
Group 3	123	20,020	44,242	17,505	93,192,018	34,520,651	127,712,669
Group 6	2	21,690	26,553	19,856	N/A	N/A	120,309,161
Bulk supply	1	N/A	32,993	25,854	N/A	N/A	152,276,311
Total	37,073	118,089	736,111	119,906			737,361,229

N/A Not used in pricing methodology

- (1) Based on 3 year 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

# **NetworkTasman**

## SEPARATION OF ESTIMATED REVENUE AND COSTS COMPONENTS TO LOAD GROUPS For the year commencing 1 April 2012.

Customer Group	Transmission Costs	Direct NW Costs	Indirect NW Costs	Depreciation	Allowable PreTax Return on ODV of Assets	Total Revenue Requirement	Total Budgeted Revenue
	\$	\$	\$	\$	\$	\$	\$
Group 1	\$ 4,709,354	\$ 3,721,348	\$ 2,012,939	\$ 3,549,002	\$ 6,172,507	\$ 20,165,150	\$ 18,509,714
Groups 2 & HLF	\$ 2,097,354	\$ 1,879,298	\$ 459,675	\$ 1,792,262	\$ 4,447,085	\$ 10,675,674	\$ 9,944,597
Group 3	\$ 1,996,003	\$ 990,844	\$ 326,828	\$ 944,955	\$ 2,373,472	\$ 6,632,101	\$ 6,282,662
Group 6	\$ 1,887,672	\$ 63,319	\$ 60,000	\$ 98,782	\$ 262,568	\$ 2,372,341	\$ 2,360,553
Bulk supply	\$ 2,511,526	\$ -	\$ 4,000	\$ -	\$ -	\$ 2,515,526	\$ 2,511,526
<b>Total</b>	<b>\$ 13,201,909</b>	<b>\$ 6,654,808</b>	<b>\$ 2,863,443</b>	<b>\$ 6,385,000</b>	<b>\$ 13,255,632</b>	<b>\$ 42,360,792</b>	<b>\$ 39,609,052</b>



# NetworkTasman

## Pursuant to Electricity Information Disclosure Requirements 2004

### Part 6. Disclosure of Line Charges.

27. Disclosure of new line charges payable by 5 or more consumers

28. Disclosure of new line charges for other consumers

#### Group Zero

		Prices <u>from</u> 01 April 2012			Prices <u>prior</u> to 01 April 2012		
Daily Charge All areas	Number of Consumers	Local Line	National Line	Total	Local Line	National Line	Total
Temporary Boxes cents/day	76	88.00	33.00	<b>121.00</b>	85.00	31.00	<b>116.00</b>
Phone Booths, PCM cabinets, Electric fences etc cents/day	98	33.00	14.00	<b>47.00</b>	32.00	13.00	<b>45.00</b>
Street Lights cents/watt/day	153	0.076	0.028	<b>0.104</b>	0.074	0.026	<b>0.100</b>

#### Group One and Group Two.

Group 1 consumers take standard supply with fusing limiting maximum demand to less than 15kVA.

Group 2 consumers take supplies with a maximum demand capacity limited to between 15 & 150 kVA.

Unit Prices							
		Prices <u>from</u> 01 April 2012			Pricing <u>prior</u> to 01 April 2012		
Tariff	Number of Consumers	Local Line	National Line	2. Total 1	Local Line	National Line	Total
		c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh
Anytime	35,307	5.95	2.27	<b>8.22</b>	5.76	2.14	<b>7.90</b>
Day (of Day/Night)	708	6.54	2.50	<b>9.04</b>	6.33	2.36	<b>8.69</b>
Controlled Water	26,077	2.76	1.03	<b>3.79</b>	2.67	0.97	<b>3.64</b>
Night	2,952	1.97	0.77	<b>2.74</b>	1.91	0.73	<b>2.64</b>
Off Peak	156	4.67	1.73	<b>6.40</b>	4.52	1.63	<b>6.15</b>
<b>Group 1 Daily Charges</b>							
	Number of Consumers	Local Line	National Line	Total	Local Line	National Line	Total
		¢/day	¢/day	¢/day	¢/day	¢/day	¢/day
All areas	34,122	11.85	3.15	15.00	11.85	3.15	15.00
<b>Group 2 Demand Charges</b>							
	Number of Consumers	Local Line	National Line	Total	Local Line	National Line	Total
All areas: cents/kVA/day	2,592	3.26	0.87	<b>4.13</b>	3.20	0.85	<b>4.05</b>

All prices exclude GST.

# NetworkTasman

**Low User Group Two.** This is a low-user pricing option for Group Two domestic customers that has a low fixed charge and higher variable charges.

		Prices from 01 April 2012			Prices prior to 01 April 2012		
Capacity of 20 kVA or 30 kVA	Number of Consumers	Local Line	National Line	Total	Local Line	National Line	Total
Variable Charge		c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh
Anytime	14	9.05	2.27	<b>11.32</b>	8.76	2.14	<b>10.90</b>
Day (of Day/Night)	2	9.64	2.50	<b>12.14</b>	9.33	2.36	<b>11.69</b>
Controlled Water	8	5.86	1.03	<b>6.89</b>	5.67	0.97	<b>6.64</b>
Night	2	5.07	0.77	<b>5.84</b>	4.91	0.73	<b>5.64</b>
Off Peak	0	7.77	1.73	<b>9.50</b>	7.52	1.63	<b>9.15</b>

Capacity 40 kVA or more	Number of Consumers	Local Line	National Line	Total	Local Line	National Line	Total
Variable Charge		c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh
Anytime	1	12.80	2.27	<b>15.07</b>	12.46	2.14	<b>14.60</b>
Day (of Day/Night)	0	13.39	2.50	<b>15.89</b>	13.03	2.36	<b>15.39</b>
Controlled Water	0	9.61	1.03	<b>10.64</b>	9.37	0.97	<b>10.34</b>
Night	0	8.82	0.77	<b>9.59</b>	8.61	0.73	<b>9.34</b>
Off Peak	0	11.52	1.73	<b>13.25</b>	11.22	1.63	<b>12.85</b>

Fixed Charge cents per day all areas	Number of Consumers	Local Line	National Line	Total	Local Line	National Line	Total
Capacity of 20 kVA or 30 kVA	16	11.85	3.15	15.00	11.85	3.15	15.00
Capacity 40 kVA or more	1	11.85	3.15	15.00	11.85	3.15	15.00

## High Load Factor - Groups 1&2

This pricing option is offered for first time from 1 April 2012 to those Group 1&2 consumers who have high annual kWh consumption relative to their network fuse capacity (kVA).

HLFC		Prices from 01 April 2012			Prices prior to 01 April 2012		
All areas	Number of Consumers	Local Line	National Line	3. Total	Local Line	National Line	Total
Tariff cents/ kWh		c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh
Anytime	0	1.61	4. 0.61	<b>2.22</b>	N/A	N/A	N/A
Day (of Day/Night)	0	1.75	0.67	<b>2.42</b>	N/A	N/A	N/A
Controlled Water	0	0.73	0.27	<b>1.00</b>	N/A	N/A	N/A
Night	0	0.50	0.20	<b>0.70</b>	N/A	N/A	N/A
Off Peak	0	1.26	0.47	<b>1.73</b>	N/A	N/A	N/A
HLF Demand Charge							
Cents/kVA/day	0	29.87	7.94	<b>37.81</b>	N/A	N/A	N/A

All prices exclude GST



# NetworkTasman

## Group Three and Six.

NETWORK TASMAN LINE CHARGE DISCLOSURE PRICING <i>from</i> 01 April 2012														
NETWORK TASMAN DISTRIBUTION (ex GST)										TRANS POWER (ex GST)				
		Unit Charges c/kWh				Demand Charges			Unit Charges c/kWh				Demand Charges	
		Summer	Summer	Winter	Winter	Anytime c/kVA/day	RCPD c/kW/day		Summer	Summer	Winter	Winter	Anytime c/kVA/day	RCPD c/kW/day
Consumers	No	Day	Night	Day	Night				Day	Night	Day	Night		
Group 3														
Category 1	4	0.42	0.24	0.76	0.24	8.46	3.06		0.0	0.0	0.0	0.0	2.44	24.02
Category 3	4	1.31	0.69	3.52	0.69	11.37	3.06		0.0	0.0	0.0	0.0	2.44	24.02
Category 4	119	1.31	0.69	3.52	0.69	12.13	3.06		0.0	0.0	0.0	0.0	2.44	24.02
Category 5	2	0.89	0.56	3.00	0.56	11.37	3.06		0.0	0.0	0.0	0.0	2.44	24.02
Total Group 3	129													
Group 6	No													
Category 6.1	1	Annual fixed charged billed monthly				\$209,603			Annual charge billed monthly				plus share of any associated Common Quality Charges and Rebates	
Category 6.2	1	Annual fixed charged billed monthly				\$224,646			Annual charge billed monthly				plus share of any associated Common Quality Charges and Rebates	
Total Group 6	2													
Embedded Network Customer														
Category 1	1	Annual fixed charged billed monthly				\$2,040 plus utilised %age R&M			Annual charge billed monthly				\$2,649,571 plus share of any associated Common Quality Charges and Rebates	

All prices exclude GST.

Group Three and Six.

# NetworkTasman

NETWORK TASMAN LINE CHARGE DISCLOSURE PRICING <i>prior</i> 01 April 2012													
NETWORK TASMAN DISTRIBUTION (ex GST)							TRANS POWER (ex GST)						
Unit Charges c/kWh				Demand Charges			Unit Charges c/kWh				Demand Charges c/kVA/day		
	Summer Day	Summer Night	Winter Day	Winter Night	Anytime	Winter	Summer Day	Summer Night	Winter Day	Winter Night	Anytime	Winter	
<b>Consumers Group 3</b>													
Category 1	0.40	0.23	0.73	0.23	8.16	3.03	0.0	0.0	0.0	0.0	2.02	19.69	
Category 3	1.28	0.67	3.43	0.67	11.09	3.03	0.0	0.0	0.0	0.0	2.02	19.69	
Category 4	1.28	0.67	3.43	0.67	11.83	3.03	0.0	0.0	0.0	0.0	2.02	19.69	
Category 5	0.87	0.54	2.93	0.54	11.09	3.03	0.0	0.0	0.0	0.0	2.02	19.69	
<b>Total Group 3</b>	<b>129</b>												
<b>Group 6</b>	<b>No</b>												
Category 1	1	Annual fixed charged billed monthly			\$204,491		Annual charge billed monthly				plus share of any associated Common Quality Charges and Rebates	\$1,527,672	
Category 2	1	Annual fixed charged billed monthly			\$219,167		Annual charge billed monthly				plus share of any associated Common Quality Charges and Rebates	\$252,594	
Total Group 6	2												
<b>Embedded Network Customer</b>													
Category 1	1	Annual fixed charged billed monthly			\$2,040 plus utilised %age R&M		Annual charge billed monthly				plus share of any associated Common Quality Charges and Rebates	\$2,496,043	

All prices exclude GST.