

Network Tasman Limited

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

Requirement 36(1)

**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 22nd day of April 2010



CIM Turner



Signature

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

Anissa Bain
Lawyer
Pitt & Moore
Richmond

Network Tasman Limited

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22 April 2010

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

Dear Sir

Disclosure of Pricing Methodology 2010-11

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 methodology and information concerning line business costs to be recovered by line charges for the 2010-11 financial year.

This information has been publicly disclosed on the company's web site and a director's statutory declaration is 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

NETWORK TASMAN LIMITED

PRICING METHODOLOGY DISCLOSURE

For Year Commencing 1 April 2010

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:
- existing pricing policies and methodologies
 - key components of revenue required to cover the costs and profits, (including transmission costs), of the line owners business activities
 - consumer groups used in the calculation of line prices and charges
 - the method of allocating costs and revenues amongst consumer groups
 - the method by which the a line owner determines the proportion of fixed and variable charges.

2.0 FINANCIAL INFORMATION

- 2.1 This pricing methodology disclosure is based on financial information drawn from NTL's line business budget and financial forecasts for the year ending 31 March 2011. These costs have been separated from NTL's other non line business activities in accordance 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 in determining NTL's line business annual revenue requirement.
- 2.3 The cost of capital for the network is calculated using NTL's estimate of WACC and the ODV valuation of systems assets established at 31 March 2004. The later is updated for capital expenditure and depreciation for the intervening period to 31 March 2010.

3.0 NETWORK TASMAN PRICING PRINCIPLES

- 3.1 NTL's pricing methodology reflects the pricing principles incorporated within the company's Statement of Corporate Intent, agreed annually between the Company and its shareholder, the Network Tasman Trust. All the shares in NTL are held by the Network Tasman Trust on behalf of the consumer beneficiaries, who elect the Trustees.
- 3.2 NTL's pricing principles as stated below, are included in both the company's SCI and in its Use of Systems Agreements with Retailers :
- A fair and reasonable rate of return to shareholders (measured on a pre-tax, pre discount basis) will be recovered
 - The cost of capital, measured on a pre tax, pre discount basis, will be reasonably allocated to, and recovered from, each group of consumers
 - Direct and indirect distribution costs and depreciation will be reasonably allocated to, and recovered from, each group of consumers
 - Transmission costs will be allocated and recovered in a manner that reasonably reflects how these costs are incurred by each group of consumers
 - Appropriate economic signals will be given to consumers relating to their use of the distribution and transmission systems

- Regulatory and public policy requirements imposed by Government, the Commerce Commission and the Electricity Commission will be accommodated within network pricing as required
- Pricing will be simple to understand, implement and administer
- Pricing will retain a reasonable level of uniformity amongst like consumers across NTL's regional areas.
- Pricing will provide certainty and medium term stability for consumers and retailers. The distribution component of pricing will be changed once, at most, in any 12 month period while the transmission component may be changed whenever Transpower alters its transmission charges.

3.3 Where any of these objectives conflict, Network Tasman Directors will use their discretion and judgement to achieve an acceptable trade off between the 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 as described in the following sections.

5.0 DISTRIBUTION SERVICES

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

- Determination of the Overall Distribution Revenue Requirement
- Identification of Load Groups
- Allocation of Distribution Costs to Load Groups
- Derivation of Distribution Prices and Revenues for Load Groups

6.0 NTL DISTRIBUTION REVENUE REQUIREMENT

6.1 The revenue requirement for the distribution 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 direct overheads
- Network General Overhead & Administration costs
- Depreciation (return of capital) which are based on ODV rates for network assets and financial reporting rates for non systems assets
- Return on capital/assets employed which is calculated by applying WACC to NTL's line business asset base valued at ODV

- 6.3 The sum of costs listed in 6.2 above equates to the line business's total distribution revenue requirement. Information on NTL's 2010-11 distribution revenue requirement by cost classification and load group can be viewed 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. It is obtained by multiplying the pre-tax cost of capital by the system and non-system asset values allocated to each load group. Systems assets are valued at ODV and non system asset values are based on their accounting book values.
- 6.5 The cost of capital (WACC) is derived using the Capital Asset Pricing Model. For the financial year commencing 1 April 2010 NTL used the following inputs:
- 5 year government stock rate to estimate the risk free rate at 5.2%
 - Target capital structure of 40% debt to total assets
 - Cost of debt 8.0%
 - Asset beta of 0.40 as the measure of the line business systematic risk
 - post tax market risk premium for equity of 7.5%
 - corporate tax rate of 30.0%

Based on these inputs NTL has calculated a pre tax cost of capital of 10.6% or a post tax WACC of 7.4% for the assets of NTL's line business

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 consumer load groups.
- 7.2 The allocation of ICP's to load groups is determined according to the:
- maximum capacity/demand an ICP can place on the network and
 - use/reliance by an ICP on particular segments of the network

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 and limited 11kV	>= 2000 kVA + hhr metering

Explanation:

- 400V/11/33kV refers to the voltage level at which the consumer takes supply and indicates the components of the network the consumer uses.

- The kVA indicates the consumers potential anytime maximum demand (AMD) and is measured by either the size of the ICP fuse installed or from historical half hourly (hhr) data available from a TOU meter installed close by the ICP.
 - Dedicated consumers are those utilising dedicated or semi dedicated feeders and network assets at voltages equal to or greater than 11kV.
- 7.3 Government policy and SCI requirements encourage 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 geographical areas.
- 7.4 Load group statistics used to allocate costs and calculate prices are presented in Appendix A.

8.0 ALLOCATION OF NETWORK COSTS TO LOAD GROUPS

8.1 Direct Network Costs, Depreciation and Capital Costs

Direct network costs, depreciation and capital costs are assigned to the network asset categories as shown in Figure 3.1 below. These network costs are then accumulated into those associated with the upper & lower segments of the network as shown in Figure 3.2.

- 8.2 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.
- 8.3 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.
- 8.4 While the lower network cost component for 11kV lines is allocated between Groups 1, 2 & 3 based on relative CMD's, 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 ALLOCATION
General 400V lines	a1	b1	r1	c1
Distribution transformers	a2	b2	r2	c2
General 11 kV lines	a3	b3	r3	c3
Dedicated 11 kV lines	a4	b4	r4	c4
Sub transmission, lines and zone subs.	a5	b5	r5	c5
Dedicated networks	a6	b6	r6	c6
TOTALS	a	b	r	c

FIGURE 3.2 NETWORK UPPER AND LOWER NETWORKS

NETWORK COMPONENT	TDC BY COMPONENT	UPPER NETWORK ALLOCATION	LOWER NETWORK ALLOCATION
General 400V lines	c1	d1	e1
Distribution transformers	c2	d2	e2

General 11 kV lines	e3	d3	e3
Dedicated 11 kV lines	e4	d4	e4
Sub transmission lines and zone subs	e5	d5	e5
Dedicated networks	e6	d6	e6
TOTALS	e	d	e

Note: 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	$(M1/A6*d)+(M1^*/A3*e)$	TDC 1
(2) 400V Gen > 15 & < 150 kVA	400	M2	A2	$(M2/A6*d)+(M2^*/A3*e)$	TDC 2
(3) 400V & 11kV > 150 kVA	400/11,000	M3	A3	$(M3/A6*d)+(M3^*/A3*e)$	TDC 3
(6) Ded. Network	Over 11000	M6	A6	$(M6/A6*d)$	TDC 6

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

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

8.5 Allocation of General Overhead and Indirect Costs

Management estimates are used to allocate the overhead and indirect costs to Group 6 & bulk supply consumers.

The remaining overhead and indirect costs are allocated to load Groups 1,2 & 3 in proportion to their relative shares of installed capacity (measured by fuse size of 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	400/11000	TDC 3	OH3	$TR3 = TDC 3 + OH3$
(6) Ded. Network	Over 11000	TDC 6	OH6	$TR6 = TDC 6 + OH6$

9.0 DERIVATION OF DISTRIBUTION TARIFFS.

9.1 **General:** The TR_i totals from figure 3.4 identify the revenue requirement for each load group recoverable 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 proportion of fixed and variable charges

- (a) NTL must strike a balance between the conflicting demands of:
- economic rationale

- government policy and regulatory requirements
 - electricity retailers desire for simplicity and predictability
 - the expectations of different electricity consumers
- (b) Economic theory encourages the use of fully cost reflective pricing. Regionally differentiated pricing associated with customers peak network demands would result. This supports economic efficiency by reflecting the fixed nature of the line business cost structures and the sunk nature of its asset based costs. The government owned grid operator Transpower operates a pricing methodology along these lines

Government policy and regulations however compel distributors to provide low fixed charge tariffs to lower use domestic consumers and to ensure rural and urban pricing structures remain closely aligned.

NTL also acknowledges some consumers and environmental groups oppose high fixed charge structures and expect a significant element of their charges to vary with consumption so some influence can be exerted over their electricity bills. These views conflict with the preferences of many high use business consumers who consider capacity based charges more fairly reflect costs of supply and reward high load factor consumers for efficient use of network assets.

- (c) Consequentially NTL distribution pricing is structured such that:
- Group 1 (both small business and residential) fixed charges are set at 15 cents per day to meet government regulatory requirements. 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.
 - Groups 2 & 3 contain larger, higher load factor business consumers so greater reliance is placed on fixed capacity based pricing (sometimes facilitated by time of use metering)
 - Group 6 consumers have fully fixed charges to reflect the high levels of asset dedication associated with their supply.
 - There is no tariff differentiation between regional areas and consequently the revenue recovered in rural areas does always fully reflect the cost of supply to those areas.
 - There is no differentiation of tariffs (fixed or variable) based on consumers end use of electricity (ie between business or domestic).
- (d) For load Group 1 there is a single fixed charge expressed as a "cents per day" charge because all consumers in this Group have the same fuse capacity limiting their maximum demands on the network to 15 kVA.
- (e) Group 2 fixed charge is expressed as "dollars per kVA of anytime maximum demand" and is applied to the range of fuse capacities (measured from 20 to 150 kVA) limiting the maximum demands of consumers within in this group.
- (f) For load Group 3 the fixed charge is expressed as:
- (i) "dollars per AMD" and
 - (ii) "dollars per Winter RCPD demand" The winter demand is the customers average demand measured coincident against the top 12 regional coincident peak demands (RCPD) on Transpower's transmission system in the upper South Island.

- (g) Variable line charges are expressed as "cents per kWh". The cents per unit charge varies across tariffs, depending on the time of use profile or the level of load interruptability the consumer commits to in advance.
- (h) The 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 NTL is to operate within the constraints imposed by Government policy requirements and the Commerce Commission's regulatory price pathway. This is particularly notable for network segments where customer density is low and where load factor is poor. Consequently Network Tasman is left to choose between deliberately breaching the price pathway or accepting a shortfall of actual distribution revenue over the total revenue requirement. To date NTL has accepted the latter.

10.0 DERIVATION OF DISTRIBUTION PRICES – Load Group 1.

- 10.1 Total 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 annual fixed charge for all ICPs is set at \$55 or 15 cents/day simply to meet Government low user regulatory requirements in a manner that minimises NTL's transaction and administration costs. This fixed charge FC1 is recovered from all consumers with no account being taken of geographical area or whether they are business or residential consumers.
- 10.3 The total variable charge VC1 recovers the residual revenue from TR1 and tariff rates are determined by dividing by the number of units consumed by Group 1, after establishing a set of relative weightings between the tariff types on offer.
- 10.4 The relative weights in part reflect the relative costs of providing network services at "peak" versus "off peak" times. The weighting provides a signal for consumers to shift consumption "off peak" and to permit components of their supply to be interrupted by NTL load control devices. The weights are allocated by management using among other factors the historic relative differences between unit charges.

Example 1.

Consider a load group with the following fictitious consumption details:

Total Group 1 Cost TR1		\$10,550,000
Number of ICPs		30,000
Tariff	Allocated Weight	Units Consumed
A	100%	38 GWh
B	65%	128 GWh
C	29%	53 GWh
D	24%	25 GWh
Total to be recovered by fixed charges		
FA1 FC per annum	=	\$55.00 pa or 15.0 cents /day
FC1	=	30,000*55
	=	\$1,650,000

Total \$ to be recovered from variable charges	=	\$10,550,000 – \$1,650,000
	=	\$8,900,000
Line Charge Tariff A	=	$\$8,900,000 / (38\text{GWh} + 128 * 0.65 + 53 * 0.29 + 25 * 0.24)$
	=	\$0.0624 per kWh of A metered consumption
Line Charge Tariff B	=	$\$0.0624 * 0.65$
	=	\$0.0406 per kWh of B metered consumption
Line Charge Tariff C	=	$\$0.0624 * 0.29$
	=	\$0.0181 per kWh of C metered consumption
Line Charge Tariff D	=	$\$0.0624 * 0.24$
	=	\$0.015 per kWh of D metered consumption

11.0 DERIVATION OF DISTRIBUTION PRICES - Load Group 2.

- 11.1 The Group 2 distribution revenue requirement TR2 is split between that to be recovered by a fixed 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 and expressed in kVA.
- 11.3 The total fixed charge revenue (FC2) is divided by the sum of all AMDs in the group 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 area.
- 11.4 The dollar per kVA tariff is multiplied by the individual ICP's AMD, to give a "demand charge" per year. This is divided by 365 and billed on a daily basis.
- 11.5 The total variable charge (VC2) recovers the residual revenue of TR2 with tariff rates determined by dividing by the number of units consumed by load group two, after establishing the relative weighting between the tariffs. This weighting uses the same rationale outlined for Group 1.

Example 2.

Consider a fictitious load group with the following profile:

Consumer AMD (kVA)

x 75

y 100

z 110

.....

Total 90,000 kVA

Total Group Cost TR2 \$3,275,000

Total Fixed Charge FC2 = 40% \$1,310,000

Total Variable Charge VC2 \$1,965,000

AMD Tariff = $\$1,310,000 / 90,000$

= \$14.56 per kVA pa.

Consumer "x" AMD Charge per day = $(14.56 * 75) / 365$

= \$3.00 per day

(The Variable charge per tariff is calculated in the same manner as Example 1)

12.0 DERIVATION OF DISTRIBUTION PRICES - Load Group 3.

- 12.1 The total Group 3 distribution revenue requirement TR3 is split between that recoverable by a fixed charge (FC3) and that recoverable by a variable charge (VC3).
- 12.2 At the beginning of the billing year the consumer's AMD and Winter RCPD are measured directly from TOU data supplied by retailers:
- Winter RCPD is the average of the consumers kW load coincident with Transpowers 12 peak loads on USI grid for the period between 1st May and 30th September for the previous year.
 - AMD is the consumers highest half hourly kVA at any time, in any month during the year.
- 12.3 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. This gives a dollar per AMD and a dollar per Winter RCPD kW tariff.
- 12.4 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. This is divided by 12 and billed on a monthly basis.
- 12.5 The total variable charge (VC3) recovers the residual revenue from TR3 not met by fixed charges and tariff rates are determined by dividing 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 the same rationale outlined for Group 1.

Example 3.

Consider a fictitious load group with the following profile:

<u>Consumer</u>	<u>AMD</u>	<u>Winter RCPD</u>
x	210	200
y	215	215
.....
Group Total	30,000	25,000
Total Group Cost TR3	\$1,500,000	
Fixed Charge recovery %	70%	
Total Fixed Charge FC3	\$1,050,000	
Fixed Charges Ratio Anytime to Winter	160%	
WMD Tariff	=	\$1,050,000 / (25,000 + 1.6 * 30,000)
	=	\$14.38 per kVA pa.
AMD Tariff	=	\$14.38 * 1.6
	=	\$23.00 per kVA pa.
Consumer "x" Winter RCPD charge	=	200 * 14.38 / 12
	=	\$240 per month
Consumer "x" AMD Charge	=	10 * 23.00 / 12
	=	\$403 per month
(The Variable charge per tariff is calculated in the same manner as Example 1)		

13.0 DERIVATION OF DISTRIBUTION PRICES - Load 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 and line charges are calculated as an annual fixed amount, and are billed monthly.

14.0 TRANSMISSION SERVICES

- 14.1 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 component within line charges.

15.0 ALLOCATION OF TRANSMISSION COSTS.

- 15.1 Transpower's transmission charges are levied on NTL in a manner which is largely 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
 - Common quality charges (if any)
 - Loss rental rebate credits
- 15.2 Connection costs and new investment charges at each Transpower grid exit point (GXP) supplying NTL's network are allocated between load groups on the basis of each group's demand contribution coincident with the AMD of that GXP. Forecast loss rental rebates are allocated to customer Groups 1, 2&3 on the basis of forecast consumption levels and are netted off total transmission costs to be recovered.
- 15.3 Interconnection charges are allocated between load groups on the basis of each group's demand level coincident with Transpower's Upper South Island RCPD 12 peak chargeable half hours recorded over the winter of the previous year.
- 15.4 The connection, new investment and interconnection costs allocated to each group are summed to determine the gross transmission costs to be recovered from that group.
- 15.5 NTL recovers transmission costs from load Groups 1-3 via a separate transmission pricing schedule within overall line charges as follows:
- (a) Consumers are classified into the same load groups in the same way 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 18.0).
 - (c) The remaining transmission costs after pass through are recovered from Group's 1-3 via NTL's standard transmission pricing schedule.

- (d) For Groups 1-3 transmission charges are recovered on a "fixed" and "variable" basis using similar rationale to that used in distribution pricing. To the extent possible within regulatory pricing constraints, NTL attempts to recover Transpower's connection and new investment costs for Groups 1 & 2 through fixed charges and the Interconnection charges through variable charges.
- (e) For load Group 1 the fixed charge is expressed as a "cents per day" charge.
- (f) For load Group 2 the fixed charge is expressed as "dollars per anytime maximum capacity" (AMD) measured in kVA and based on customer fuse size.
- (g) For load Group 3 the fixed charge is expressed as "dollars per kW of Winter RCPD" and "dollars per kVA" of AMD, and is based on data from time of use meters. The Winter RCPD component directly passes through Transpower's interconnection charges to these consumers while the AMD component recovers connection costs attributable to this group.
- (h) The variable Transpower charge is expressed as "cents per unit (kWh)" for Groups 1 & 2 and varies across tariffs, depending on the historical usage profile and load control availability. There are no variable (kWh) transmission charges for Group 3 consumers.

16.0 FIXED TRANSMISSION CHARGES FOR GROUPS 1 - 3

16.1 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 and the result is the annual Group 1 charge per ICP.

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

16.2 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).

Each ICP within Group 2 has an Anytime Maximum Demand (AMD) that is the same as described in the Group 2 fixed distribution charge calculation above.

The total fixed charge (TFC2) is divided by the sum of all individual AMDs within Group 2. This gives a dollar tariff per kVA of AMD per annum.

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

16.3 Group 3

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

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

The interconnection 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.

17.0 VARIABLE TRANSMISSION CHARGES GROUPS 1-3

- 17.1 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), ripple controlled consumption or summer only 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.
- 17.2 A relative weighting is applied to differentiate peak and non peak tariffs for each group.
- 17.3 The total amount to recover by this variable charge (TVCi) for each group is then divided by total kWh consumption, having established the weighting to the peak and of peak tariffs in (17.2) above.
- 17.4 There is no variable tariff used in Group 3 pricing to recover transmission costs.

Example 4.

Consider the following Groups with fictitious loads as shown:

	Area 1	Area 2	Total
Group 1 RCPD	37,000	8,000	45,000 kW
Group 2 RCPD	20,000	5,000	25,000 kW
Group 3 RCPD	17,000		17,000 kW
Group 6 RCPD	20,000		20,000 kW
RCPD at GXPs	94,000	13,000	107,000 kW
Total Transmission Cost			\$8,200,000
Proportion to be recovered from fixed charges:			
Group 1		0.10	
Group 2		0.15	
Group 3		1.00	
Group 6		1.00	
Group 1 ICPs		30,000	
Group 2 AMD		94,000 kVA	
Group 3 AMD		30,000 kVA	
Group 3 Winter RCPD		17,000 kW	

Group 6 CMD		20,000 kVA
Group 1 Units Consumed on Peak		205 GWh
Group 1 Units Consumed Off Peak		45 GWh
Group 1 Weighting of Off Peak to Peak		46%
(i.e. the Off Peak tariff is 46% of the Peak tariff)		
TT1	=	$45,000 / 107,000 * \$8.2m$
	=	\$3,449,000
TT2	=	$25,000 / 107,000 * \$8.2m$
	=	\$1,916,000
TT3	=	$17,000 / 107,000 * \$8.2m$
	=	\$1,302,000
TFC1	=	$0.10 * \$3,449,000$
	=	\$344,925
G1 Fixed Charge		
TFA1	=	$\$344,925 / (30,000) / 365 * 100$
	=	3.15 cents per day
TFC2	=	$0.15 * \$1,915,888$
	=	\$291,400
G2 Fixed Charge		
	=	$\$291,400 / 94,000$
	=	\$3.10 per kVA pa
TFC3 Total	=	\$1,302,000
TFC3a Connection	=	\$ 228,000
TFC3b Interconnection	=	\$1,070,000
G3 Fixed Charges		
TFC3a Connection	=	$\$228,000 / 30,000$
	=	\$7.60 per kVA of AMD
TFC3b Interconnection	=	$\$1,070,000 / 17,000$
	=	\$62.94 per kW of Winter RCPD/ pa.
G1 Peak Variable Tariff	=	$(1 - 0.10) * \$3,449,000 / (205 \text{ GWh} + 0.45 * 40 \text{ GWh})$
	=	\$0.0140 per kWh
G1 Off Peak Tariff	=	$0.45 * \$0.0140$
	=	\$0.0063 per kWh
Similarly for G2 Peak and Off Peak variable transmission tariffs		

18.0 TRANS POWER CHARGES - GROUP 6 & BULK SUPPLY .

- 18.1 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 from the underlying Transpower charging methodology
- 18.2 Connection and new investment charges are allocated to each Group 6 customer in proportion to their demands co-incident with the relevant GXP's chargeable demands and are billed as a monthly fixed amount.

Example 5.

Consider a fictitious bulk supply point with the following characteristics:

Trans Power Connection Charge	\$800,000
Chargeable AMD for the GXP	103 MVA
Group 6 Consumer CMD	18.5 MVA
Consumer Transmission Charge	= $18.5 / 103 * \$800,000$

= \$143,689 pa. or \$11,974 per month

- 18.3 Interconnection charges are passed through directly at the Transpower charge rate and are levied on the consumers demand (grossed up of distribution network losses) coincident with the Upper South Island RCPD chargeable demands.
- 18.4 Common Quality Service Charges and Loss Rental Rebates are passed directly through to Group 6 consumers each month on the same basis as they are credited or charged to NTL by Transpower.

Appendix A

NETWORK TASMAN LIMITED

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

Forecast for year commencing 1 April 2010

Customer Group	Number of ICP's	Coincident Maximum Demand	Anytime Maximum Capacity	Winter Maximum RCPD	Consumption Peak	Consumption Off Peak	Total Consumption
	#	kW	kVA	kW	kWh	kWh	kWh
Group 1	33,557	56,252	503,355	53,356	171,859,649	69,762,504	241,622,153
Group 2	2,528	23,900	113,071	19,374	86,373,587	12,976,305	99,349,892
Group 3	114	17,672	41,669	15,628	86,966,524	31,929,130	118,895,654
Group 6	2	19,824	26,307	15,248	N/A	N/A	155,982,044
Bulk supply	1	N/A	34,232	30,286	N/A	N/A	116,739,767
Total	36,202	117,648	718,634	133,892			732,589,510

N/A Not used in pricing methodology

- (1) Based on 3 year rolling average
- (2) Based on customer installed fuse capacity
- (3) Based on Time of Use metering data

SEPARATION OF ESTIMATED REVENUE AND COSTS COMPONENTS TO LOAD GROUPS

For the year commencing 1 April 2010

Customer Group	Transmission Costs	Direct NW Costs	Indirect NW Costs	Depreciation	Allowable PreTax Return on ODV of Assets	Total Revenue Requirement
	\$	\$	\$	\$	\$	\$
Group 1	\$ 4,883,224	\$ 3,628,737	\$ 1,459,302	\$ 3,239,253	\$ 8,193,551	\$ 21,404,068
Group 2	\$ 1,845,212	\$ 1,603,785	\$ 327,810	\$ 1,431,646	\$ 4,685,312	\$ 9,893,765
Group 3	\$ 1,455,111	\$ 859,147	\$ 184,966	\$ 766,932	\$ 2,433,704	\$ 5,699,859
Group 6	\$ 1,142,772	\$ 59,583	\$ 28,000	\$ 85,411	\$ 297,050	\$ 1,612,816
Bulk supply	\$ 2,260,504	\$ -	\$ 24,000	\$ -	\$ -	\$ 2,284,504
Total	\$ 11,586,823	\$ 6,151,253	\$ 2,024,078	\$ 5,523,242	\$ 15,609,617	\$ 40,895,013