

Nelson Electricity Ltd



Revised Pricing Methodology Disclosure 2006

Nelson Electricity Limited

Pricing Methodology Disclosure

For the period beginning 1 April 2006

The following information is disclosed in accordance with the Electricity Information Disclosure Requirements 2004 – Sections 22 & 23.

The Derivation of charges is described in the following sections.

- Customer Groups
- Customer Group Statistics
- Allocation and Recovery of Network and Transmission Charges
- Cost Recovery per Load Group
- Fixed v's Variable Charges
- Price Path Threshold Implications
- Pricing Schedules

Consumer Groups or Load Groups

Consumer Groups are based on typical load patterns, fuse size and annual kWh consumption. Consumers are grouped into 7 categories.

- Load Group 1
Domestic consumers – Connections that are a domestic home that exhibit a typical domestic load profile. The connection is typically 15kVA or less. The NEL Network Code allows for single phase 60amp, two phase 40 amp or three phase 30amp supplies to be classed as a domestic. A domestic type load profile with a connection above the fuse sizes mentioned are categorized as Load Group 2a.
- Load Group 2a
Small Business consumers – Connections that are 150kVA or less and use less than 100,000kWh per year. Domestic consumers greater than 15kVA are also in this group.
- Load Group 2b
Consumers with capacity supplied of greater than 150kVA or annual consumption of greater than 100,000kWh with supply from the 400V network.
- Load Group 3
Consumers with capacity supplied of greater than 150kVA or annual consumption of greater than 100,000kWh with dedicated 400V supply from a 11kV/400V substation.
- Load Group 4
Consumers with capacity supplied of greater than 150kVA or annual consumption of greater than 100,000kWh with supply from a dedicated 11kV/400V substation.
- Load Group 5
Consumers with capacity supplied of greater than 1500kVA with supply from a dedicated 11kV/400V substations.
- Load Group 6
Consumers with capacity supplied of greater than 3000kVA with supply from a dedicated 11kV/400V substations.

NEL has combined groups 2a, 3 and 4 due to the numbers being low and that there is little difference between each consumer group.

Consumer Group Statistics

Statistics are collected and analysed as per the customer groupings as described in the previous section. This information is used as a base to NEL's pricing allocations as described further in this report. Information is as follows:

- Number of Connections per group.

Number of Connections	
Load Group	Connections
1	7,336
2a	1,330
2b,3 and 4	90
5	1
6	1
Total	8,758

- Anytime Peak per group.

Anytime Peak	
Load Group	Peak kVA
1	18,665
2a	8,491
2b, 3 and 4	11,784
5	1,667
6	3,250
Total	43,857

- Winter Demand Peak per group.

Control Period Demand (Winter Demand)			
kVA			
Load Group	8:30 am - 11:30 am	5:00 pm - 6:00 pm	CPD Allocation
1	10,032	16,086	11,236
2a	7,671	4,824	7,100
2b, 3 and 4	11,018	7,878	10,389
5	1,350	890	1,258
6	2,629	2,629	2,629
Total	32,700	32,308	32,612

Nelson Electricity has a winter load that peaks between 8:30 am - 11:30 am and 5:00 pm - 6:00 pm. The morning load is predominantly business load and the evening peak is typically influenced by the domestic. The statistics required are to ensure the right pricing signals are sent to each group and that charges are as fair and equitable as possible to all connections. The Winter Demand is a critical part to the allocation of Transmission Costs between groups.

- GWh per group.

GWh			
Load Group	Winter	Summer	Total
1	28.712	27.029	55.741
2a	13.544	15.626	29.170
2b, 3 and 4	18.008	22.973	40.981
5	2.399	3.150	5.549
6	7.674	9.237	16.911
Total	70.337	78.015	148.352

These figures are estimated consumption per Load Group with no loss allocation back to GXP. Winter months are May – September, Summer months are October – April.

- ODRC per group allocation

ODRC						
Asset Group	1	2a	2b, 3 and 4	5	6	Total
33kV Lines	\$435,049	\$274,901	\$402,222	\$48,707	\$101,789	\$1,262,667
Zone Sub	\$279,001	\$176,297	\$257,949	\$31,236	\$65,278	\$809,761
11kV Lines	\$2,208,516	\$1,319,706	\$1,377,432	\$205,507	\$216,373	\$5,327,534
11kV/400V Sub	\$1,867,973	\$1,116,214	\$1,165,038	\$173,819	\$183,009	\$4,506,052
400V Lines	\$5,064,919	\$1,195,884	\$773,807	\$0	\$0	\$7,034,610
Other	\$559,381	\$334,260	\$348,881	\$52,052	\$54,804	\$1,349,377
Total	\$10,414,838	\$4,417,261	\$4,325,329	\$511,320	\$621,252	\$20,290,000

ODRC allocation is assessed on each load group's utilisation of assets. As an example, Groups 5 and 6 do not utilise any of the 400V lines so there is no value assigned to those groups.

- Cost of Capital

Factor	Rate
Company Tax Rate on Debt	33%
Investor Tax Rate on Equity	28%
Cost of Debt, before Tax	8.05%
Risk Free Rate of Return	7.05%
Asset Beta	0.45
Equity Beta	0.90
Debt Ratio	50%
Market Risk Premium	8%

The above parameters are based on advice from Marlborough Lines Ltd, a shareholder of Nelson Electricity Ltd.

On the basis of the above input parameters, the Nelson Electricity Ltd Weighted Average Cost of Capital (WACC) is 8.9% of ODRC = \$1,806k .

Allocation and Recovery of Network and Transmission Charges

Network Charges are set to recover indirect operating costs, direct operating costs, depreciation and cost of capital. The setting of the charges also takes into account historical charging practices and methodologies.

The company annual revenue requirements for 2006 are:

Operating Costs (Network R&M)	\$594k
Transmission Costs	\$1,934k
Overhead Costs	\$1,241k
Depreciation	\$1,066k
Target Return	\$2,488k

With the Nelson Electricity being a small predominantly urban network there was no need to sectionalize it into separate pricing areas.

Cost Recovery per Load Group

Following is a table outlining the cost recoveries per load group (\$000,s).

Load Group	Operating	Transmission	Overhead	Depreciation	Target Return	Total
1	\$305	\$728	\$632	\$547	\$1,276	\$3,487
2a	\$121	\$449	\$230	\$218	\$509	\$1,528
2b,3,4	\$139	\$525	\$270	\$250	\$584	\$1,769
5	\$10	\$69	\$28	\$17	\$41	\$165
6	\$19	\$163	\$80	\$34	\$78	\$374
Total	\$594	\$1,934	\$1,241	\$1,066	\$2,488	\$7,323

The methodology used for the above cost apportionment is as follows:

- Operating Costs – Operating costs is the Operational Expenditure Budget that covers both the planned and unplanned network R&M expenditure on the network. The Operational Expenditure Budget is split into the different asset types as per the ODRC groups. The asset group expenses are then allocated to each load group according to the ODRC proportions for each asset group.
- Transmission Costs – Transmission costs are an unavoidable cost, it covers the upstream costs from our subtransmission connection point at STK0331. The major component in transmission costs is the Interconnection charge (system peak based). Transmission peaks are typically encountered during mid winter during the weekday morning. Transmission costs are split between load groups based on their influence on these peaks.
- Overhead Costs – Are apportioned by using two measures; the number of network connections and the maximum demand of the load group. This gives a balance of spreading overhead costs between the business of selling capacity and the number of consumers connected.
- Depreciation – This is apportioned by using the assessed depreciation using the Nelson Electricity ODV model. The apportioning is as per the assessed ODRC value change per load group between years 2005 and 2006.
- Target Return - This is apportioned to load groups as per the ODRC % split per load group. It is, however, important to note that the ODV valuation process still undervalues the underground network value and so the target return takes this into account.

Fixed v's Variable Charges

The proportion of charges that are fixed and variable have been set based on the historical pricing methodologies. Nelson Electricity has maintained a pricing mix that has been consistent for over ten years and as the previous pricing methodology was working, there was no compelling reason to change to proportions.

The only major variation has been the provision of a low daily fixed charge option for domestic consumers. This introduces a cross subsidization, which the pricing structures of previous years had been designed to remove.

Currently overall the proportions between fixed and variable line charges are 50% Fixed and 50% Variable. Groups 1 and 2a have a higher variable proportion while groups 2b, 3, 4, 5 and 6 have a higher fixed proportion.

Nelson Electricity is in the business of selling capacity and most of its costs as identified above are fixed. If the true proportion of fixed and variable costs were charged in the same proportions to all consumers, the fixed charge proportion of groups 1 and 2a consumers would increase significantly with the variable charges reduced.

- **Load Group 1 - Domestic Consumers**

Network costs are broken down into the following:

- Fixed Daily Charge
- Variable kWh Charge. This charge value depends on whether the load is controlled by ripple control or uncontrolled.

For the average Group 1 customer, fixed charges recover approximately 48% of total network costs.

- **Load Group 2a - Small Business Consumers**

Network costs are broken down into the following:

- Fixed Daily Charge.
- Variable kWh Charge. This charge value depends on whether the load is controlled by ripple control or uncontrolled.

For the average Group 2a customer, fixed charges recover approximately 29% of total network costs.

- **Load Groups 2b, 3, 4, 5, 6. - Time of Use Consumers**

These charges are for the larger installations on the network. These sites have Time of Use metering installed. Nelson Electricity can set network charges based on the individual sites configuration and usage pattern accurately. Network Costs are broken down into four categories.

- Installation Charge - This is a fixed per installation charge.
- Capacity Supply Charge - Based on the installations fuse size or transformer size.
- Winter Demand - This is the installations maximum half hour demand in the Winter Demand time zones as described earlier.
- kWh Charge - A variable charge based on the kWh consumption.
- Power factor penalty charge for sites that have a pf < 0.95.

The overall proportion of fixed v's variable charges for Time of Use consumers varies greatly due to the differing types of consumers. This pricing methodology attempts to ensure every Time of Use consumer pays its fair share of line charges and is not subsidized by other Time of Use consumers. The average consumer will have approximately 62% charges as fixed charges.

Price Path Threshold Implications

NEL has to set prices at least 60 days prior to them coming into effect to give electricity retailers time to implement changes. This is as per the terms of the Conveyance and Use of System Agreement between NEL and electricity retailers. This means that the new prices applicable from 1 April 2006 had to be set in January 2006.

At the time of setting prices for 1 April 2006, NEL was aware that due to excessive transmission Loss Rental Rebates received through the year that we would inadvertently breach the 31 March 2006 Price Path Threshold by an estimated \$151k.

NEL decided to pass back the excessive revenue by reducing the revenue for year ending 31 March 2007 by the equivalent of the estimated breach value. The target Maximum Revenue based on 1 April 2007 prices and 2003 Quantities was thus reduced from \$7,208k down to \$7,056k. The basis for the revenue reduction is detailed below.

Estimated Threshold Compliance Position - January 2006

Assessed Revenue Position for 31 March 2006	January Estimate
Max Notional Rev 31 March 2005	\$5,029,480
CPI-X adjustment estimate	2.10%
Max Notional Rev 31 March 2006	\$5,135,099.08
Pass Through Costs	
Estimated Transmission (Including LRR)	\$1,497,234.01
Loss Rental Rebate Estimate	LRR estimates @\$25,000 /month
Estimated Rates	\$10,958.46
Estimated Electricity Commission	\$31,209.42
Assessed Maximum Allowable Revenue at PMar06 x QMar03	\$6,674,501
Actual Notional Revenue at PMar06 X QMar03	\$6,825,983
Estimated Breach	\$151,482

Assessed Revenue Position for 31 March 2007	31 March 2007 Threshold Compliance Estimate
Max Notional Rev 31 March 2006	\$5,135,099
CPI-X adjustment estimate	2.10%
Max Notional Rev 31 March 2007	\$5,242,936
Estimated Pass Through Costs	
Estimated Transmission (Including LRR)	\$1,934,626
Loss Rental Rebate Monthly Estimate.	LRR @ \$10,000 / month
Estimated Rates	\$12,000
Estimated Electricity Commission	\$18,000
Assessed Maximum Revenue at PMar07 x QMar03 (excluding 31 March 2006 Breach)	\$7,207,562
Less 31 March 2006 Estimated Breach	\$151,482
NEL Assessed Maximum Revenue at PMar07 x QMar03	\$7,056,080
NEL Pricing Estimated Notional Revenue	\$7,050,945
NEL will not breach the 31 March 2007 Threshold by	\$5,135

The table on the next page demonstrates the assessed maximum notional revenue as at 31 March 2007 based on the 1 April 2006 prices and 2003 quantities will be \$7,051k (\$5,135 below the assessed maximum allowable revenue). This equates to total revenue of \$7,323k using 2006/2007 estimated quantities.

Pricing Schedules

Price Option	Unit Charges	Line Charges from 1 April 2006		
		Local Line	National Line	Total Line
<u>RESIDENTIAL</u>				
STANDARD				
<i>Fixed</i>	cents/day	63.000	0.000	63.000
<i>Variable</i>				
General	cents/kWh	2.325	1.585	3.910
Controlled	cents/kWh	1.392	0.918	2.310
Night Rate	cents/kWh	0.986	0.474	1.460
ECONOMY				
<i>Fixed</i>	cents/day	15.000	0.000	15.000
<i>Variable</i>				
General	cents/kWh	5.025	1.585	6.610
Controlled	cents/kWh	2.792	0.918	3.710
Night Rate	cents/kWh	1.586	0.474	2.060
<u>BUSINESS</u>				
STANDARD				
<i>Fixed</i>	cents/day	100.000	0.000	100.000
<i>Variable</i>				
General	cents/kWh	2.325	1.585	3.910
ECONOMY				
<i>Fixed</i>	cents/day	63.000	0.000	63.000
<i>Variable</i>				
General	cents/kWh	4.025	1.585	5.610
NIGHT SAVER				
<i>Fixed</i>	cents/day	100.000	0.000	100.000
<i>Variable</i>				
Day	cents/kWh	2.725	1.585	4.310
Night	cents/kWh	0.986	0.474	1.460
CONTROLLED				
Controlled	cents/kWh	1.392	0.918	2.310
Priority Control	cents/kWh	1.642	0.918	2.560
Night rate	cents/kWh	0.986	0.474	1.460

All prices are GST exclusive

Time of Use Prices

TOU Site > 150kVA or > 100,000 kWh

NETWORK CHARGES:

Metered Installation (\$/Metered Installation/Yr)
Energy (c/kWH)

Winter Demand - 2 Options

Power Factor > 0.95

Winter Demand (\$/WD kW/Yr)

or

Power Factor < 0.95 or with kVA metering

Winter Demand (\$/WD kVA/Yr)

Capacity Supplied

Group3 15kVA - 42kVA
Group4 43kVA - 69kVA
Group5 70kVA - 110kVA
Group6 111kVA - 138kVA
Group7 139kVA - 218kVA
Group8 219kVA - 300kVA
Group9 301kVA - 500kVA
Group10 501kVA - 750kVA
Group11 751kVA - 1000kVA
Group12 1001kVA - 1500kVA

Prices From 1 April 2006		
Total	NEL Network	Transpower
479.93	479.93	0.00
1.500	0.749	0.751
Total	NEL Network	Transpower
56.83	35.78	21.05
Total	NEL Network	Transpower
53.98	33.98	20.00
Total	NEL Network	Transpower
Charge \$/Yr	Charge \$/Yr	Charge \$/Yr
613.83	613.83	0
1008.43	1008.43	0
1,607.65	1,607.65	0
2,016.87	2,016.87	0
3,186.07	3,186.07	0
4,384.50	4,384.50	0
7,307.50	7,307.50	0
10,961.25	10,961.25	0
14,615.00	14,615.00	0
21,922.50	21,922.50	0

TOU Site > 2000kVA

NETWORK CHARGES:

Fixed (\$/Yr)
Winter Demand (\$/Winter Demand kVA/Yr)
Energy (c/kWH)
Capacity Supplied (\$/kVA/Yr)

Prices From 1 April 2006		
Total	NEL Network	Transpower
0.000	0.000	0.000
79.005	25.005	54.000
0.307	0.160	0.147
13.490	13.490	0.000