

# **AURORA ENERGY LTD**

## **Use-of-System Pricing Methodology**

Methodology Applicable from 1 April 2007

Prices Applicable from 1 April 2007

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## **1 INTRODUCTION**

This document outlines the methodology by which use-of-system charges (line charges) are determined. It has been developed following consultation with various interested parties and comments and suggestions for improvement are welcome at any time. Included is all the information required by Sections 22 and 23 of the Electricity Information Disclosure Requirements 2004 as published by the Commerce Commission.

## **2 PRICING OBJECTIVES**

### **2.1 Revenue**

Aurora Energy Ltd (Aurora) must obtain sufficient revenue to:

- (a) meet its contractual obligations for connection to the Transpower grid;
- (b) meet its contractual obligations for delivery of energy over the distribution network;
- (c) comply with statutory requirements on public safety, environmental protection and quality of supply;
- (d) provide a commercially appropriate return on funds.

### **2.2 Efficiency**

Improvements in the efficiency of electricity delivery will be achieved by promoting efficient investment in and operation of the network, by clearly signalling the fixed and variable costs of delivery.

### **2.3 Fairness**

As a supplier of an essential service, Aurora intends to set fair and reasonable prices. Delivery charges as a whole are cost-based and the recovery of those costs will be spread fairly over users of the network. The application of fairness to delivery pricing is one of the most difficult objectives to achieve, because users have varying views on what is fair - based to a large extent on how the pricing methodology impacts on their individual line charges.

The pricing methodology follows closely the recommendations of the Ministry of Commerce document "Electricity Disclosure Guidelines". These guidelines recognise amongst other aspects that:

- (a) individual delivery charges should reflect the costs of supplying each connection point - the level of charges should take into account the power to be delivered, the number and type of circuits and the condition and age of the assets;
- (b) where individual delivery charges do not apply, consumers are placed in load capacity groups; each group's charges will vary according to their respective use of different types of assets;
- (c) where new investment is required, those users who obtain the benefit should be required to contribute towards the cost.

The above guidelines have been modified in order to comply with the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004, which requires domestic consumers to have the fixed portion of their electricity account limited to 10% of the account (as calculated by reference to the average domestic consumer). This has been applied to the recovery mechanism used for costs in load groups L1 and L1A only.

### 3 COST STRUCTURE

The pricing methodology is based on cost recovery. Consequently, the price structure closely relates to the corresponding cost structure. The following cost categories are involved:

#### 3.1 Distribution Costs

Distribution costs derive from two cost drivers.

**Asset Costs:** (94% of total distribution costs)

- (a) provision of assets - the cost of funding including return to shareholder;
- (b) maintaining the assets to safety, legal, consumer and economic requirements;

**System Operation Costs:** (3% of total distribution costs)

- (a) provision of fault response services;
- (b) provision of congestion signalling facilities to minimise investment in the transmission and distribution networks, and to provide energy retailers and their customers with a load switching services which may not relate to network investment.

**Overhead Costs:** (3% of total distribution costs)

- (a) provision of support services related to the above items.

The variation of these costs per \$ of capacity provided for consumer use is significant between GXPs, as follows:

**Variation of \$ORC\* asset per MW**

	ORC	MW peak	ORC/MW	
Clyde	\$ 56,117,299	16.3	\$3,442,779	226%
Cromwell	\$ 81,114,175	24.2	\$3,351,825	220%
Frankton	\$ 71,143,908	43.8	\$1,624,290	107%
South Dunedin	\$ 77,592,558	67.9	\$1,142,748	75%
Halfway Bush	\$136,929,305	125.2	\$1,093,685	72%
Weighted Average	\$422,897,245	277.4	\$1,524,523	100%

\* Optimised Replacement Cost (ORC) is a standardised measure of the "used and useful" distribution assets.

Optimised Depreciated Replacement Cost of assets has not been used in the above illustration because ORC is less susceptible to significant variation when large zone substation and transmission assets are replaced or upgraded. Older assets also generally require more maintenance and a ratio using ODRC does not appropriately reflect these higher maintenance costs.

### 3.2 Transmission Costs

Transmission costs are determined by Transpower NZ Ltd's pricing methodology, which is by Grid Exit Point (GXP), using the following price components:

**Interconnection Charge:** (88% of transmission costs)

This charge is based on the average of the 12 highest peak demands at each GXP in the previous 12 months.

**Connection Charge:** (12% of total transmission costs)

This charge represents the fixed connection costs associated with the dedicated assets at each grid exit point.

The variation of these costs per MW of capacity provided for consumer use is significant between GXP, as follows:

**Variation in \$ of transmission cost per MW**

GXP	\$/MW	% of average
Clyde	\$66,417	105%
Cromwell	\$61,745	98%
Frankton	\$82,155	130%
Halfway Bush	\$57,212	91%
South Dunedin	\$61,382	97%
Weighted Average	\$63,107	100%

### 3.3 Combined Transmission and Distribution Costs

When the cost driver ratios are combined the following composite ratios result.

GXP	Transmission	Distribution	Composite	50% Target	Price Zone
Weighting	29%	71%	100%	100%	
Clyde	105%	226%	191%	144%	CML & CYD
Cromwell	98%	220%	185%	144%	CML & CYD
Frankton	130%	107%	113%	107%	FKN
Halfway Bush	91%	72%	77%	89%	SDN & HWB
South Dunedin	97%	75%	81%	89%	SDN & HWB
Average	100%	100%	100%	100%	

Due to the significant differences in the cost driver ratios, three pricing areas are used. This is a reasonable compromise between appropriately signalling the very different investment costs in each location, while keeping complexity to a minimum.

Distribution costs are thus predominantly related to asset value, with the result that a strict application of cost-recovery would mean that each consumer paid charges related to the assets they use.

At the January 2002 Directors meeting it was decided that pricing should recover a minimum of 50% of the full delivery costs in each of the three pricing areas of Dunedin (SDN & HWB), Central (CML & CYD) and Central (FKN) and the current target is defined in the table above.

### 3.4 Overall Revenue Requirements for Year Ended 31 March 2008<sup>1</sup>

Target weighted average cost of capital		\$ 26.325 million
Expenses		
Network depreciation	\$10.335 million	
Other	\$14.938 million	
		\$ 25.273 million
Tax expense		\$ 12.880 million
Target distribution revenue		\$ 64.478 million
Transmission services		\$ 18.834 million
Target delivery revenue		\$ 83.312 million
Less regulatory discount		\$ 19.007 million
Total delivery revenue budgeted for 2007/08		\$ 64.305 million

This revenue requirement is derived from the three pricing areas as follows:

	Distribution \$ million	Transmission \$ million	Total \$ million
Dunedin HWB & SDN area	27.122	11.793	38.915
Central CML & CYD area	11.562	2.674	14.236
Central FKN area	6.787	4.367	11.154
Total	45.469	18.834	64.305
Weighting	71%	29%	100%

The allocation of these area requirements is shown in section 3.5, where they are allocated to the load groups detailed in section 4.3.

<sup>1</sup> As Aurora has a 30 June balance date, the dollar values have been taken from the last quarter of the 2006/07 budget and the first three quarters of the 2007/08 budget.

### 3.5 Load Group Characteristics and Area Cost Allocations

The statistical parameters used for the allocation of area costs to load groups are as follows:

#### Statistics for the Dunedin Area GXP's of Halfway Bush and South Dunedin

Group	kVA Range	Number of Connections to the Network	Energy Delivered Per Annum GWh	Group Anytime Demand MW	Sum of Installed Capacity MVA	Group Congestion Period Demand MW
St L	0	2	7.1	1.6	6.6	1.07
L1	0 - 15	49,224	466.0	139.5	729.7	102.75
L2	16 - 149	2,710	146.0	32.1	137.9	24.88
L3	150 - 499	190	92.0	23.0	48.6	16.27
L4	500 - 2499	60	93.0	19.5	43.4	14.10
L5	2500+	10	105.0	18.7	41.5	16.26
Total		52,196	909.1	234.5	1007.7	175.33

#### Dunedin Area Distribution Costs by Asset \$000

Total Asset Costs by Asset Class	Total \$
33kV Lines	1,980
Zone Substations	5,821
HV Lines	6,958
Distribution Substations	5,933
LV Lines	6,430
Total	27,122

#### Dunedin Area Distribution Costs Allocated to Load Groups \$000

	Street Lighting	L1	L2	L3	L4	L5	W33	Total
33kV lines	12	1,104	261	178	153	161	111	1,980
Zone substations	38	3,437	812	555	476	503	-	5,821
HV lines	52	4,411	1,046	715	522	112	-	6,958
Distribution substations	49	3,907	995	678	198	106	-	5,933
LV lines	57	5,102	1,204	67	-	-	-	6,430
Total	208	17,961	4,318	2,193	1,349	882	111	27,122

#### Transmission Costs Allocated to Dunedin Area Load Groups \$000

	Street Lighting	L1	L2	L3	L4	L5	W33	Total
Transmission	71	6,877	1,700	1,101	954	1,090	-	11,793

**Statistics for the Central Area GXP's of Cromwell and Clyde**

Group	kVA Range	Number of Connections to the Network	Energy Delivered Per Annum GWh	Group Anytime Demand MW	Sum of Installed Capacity MVA	Group Congestion Period Demand MW
St L	0	2	1.6	0.4	1.4	0.23
L1	0 - 15	14,119	105.3	36.4	205.8	32.25
L2	16 - 149	1,209	56.0	12.0	65.1	7.68
L3	150 - 499	73	19.4	7.8	16.3	3.17
L4	500 - 2499	9	10.0	4.5	6.9	1.67
L5	2500+	0	0.0	0.0	0.0	0.00
Total		15,412	192.3	61.1	295.5	45.00

**Distribution Costs for Clyde and Cromwell by Asset \$000**

Total Asset Costs by Asset Class	Total \$
33kV Lines	915
Zone Substations	1,445
HV Lines	5,469
Distribution Substations	2,219
LV Lines	1,514
Total	11,562

**Distribution Costs for Clyde and Cromwell Area Allocated to Load Groups \$000**

	Street Lighting	L1	L2	L3	L4	L5	P33	Total
33kV lines	4	463	129	70	39	-	210	915
Zone substations	8	949	265	143	80	-	-	1,445
HV lines	30	3,590	1,004	542	303	-	-	5,469
Distribution substations	13	1,529	432	228	17	-	-	2,219
LV lines	10	1,138	321	45	-	-	-	1,514
Total	65	7,669	2,151	1,028	439	-	210	11,562

**Transmission Costs for Clyde and Cromwell Area Allocated to Load Groups \$000**

	Street Lighting	L1	L2	L3	L4	L5	P33	Total
Transmission	14	1,844	489	212	115	-	-	2,674

**Statistics for the Frankton Area GXP**

Group	kVA Range	Number of Connections to the Network	Energy Delivered Per Annum GWh	Group Anytime Demand MW	Sum of Installed Capacity MVA	Group Congestion Period Demand MW
St L	0	1	1.2	0.2	1.0	0.16
L1	0 - 15	9,370	90.0	29.9	126.6	26.49
L2	16 - 149	1,081	55.0	14.5	53.2	9.29
L3	150 - 499	60	27.1	7.9	15.3	4.65
L4	500 - 2499	18	28.2	8.5	13.4	5.07
L5	2500+	1	3.5	3.2	4.5	1.31
Total		10,531	205.0	64.2	214.0	46.97

**Distribution Costs for Frankton area by Asset \$000**

Total Asset Costs by Asset Class	Total \$
33kV Lines	340
Zone Substations	1,092
HV Lines	2,793
Distribution Substations	1,237
LV Lines	1,325
Total	6,787

**Distribution Costs for Frankton Area Allocated to Load Groups \$000**

	Street Lighting	L1	L2	L3	L4	L5	P33	Total
33kV lines	1	175	72	38	41	13	-	340
Zone substations	4	541	231	121	131	64	-	1,092
HV lines	10	1,459	614	321	347	42	-	2,793
Distribution substations	5	693	312	162	65	-	-	1,237
LV lines	6	904	375	40	-	-	-	1,325
Total	26	3,772	1,604	682	584	119	-	6,787

**Transmission Costs for Frankton Area Allocated to Load Groups \$000**

	Street Lighting	L1	L2	L3	L4	L5	P33	Total
Transmission	16	2,240	932	496	543	140	-	4,367



## 4 REVENUE STRUCTURE

Use-of-system charges closely follow the methodology recommended by the Ministry of Commerce document "Electricity Disclosure Guidelines 1994" and modified as discussed in section 2.3 to meet the Government's regulatory requirement for Standard Domestic consumers. These guidelines recommend revenue allocations by load groups according to their general usage of asset classes.

### 4.1 Variations from Ministry of Commerce Guide

Where options or variations to the Ministry of Commerce Guide have been adopted, then these are outlined below:

- a) Costs are allocated to each load group on the basis of asset use and in the ratio of 50% group Anytime Demand and 50% group Congestion Period Demand, instead of the 100% group Anytime Demand method in the Guide. This improves the signalling of investment costs to users who cause the investment.
- b) Charges apply per Installation Control Point (ICP).
- c) Rural or remote rural loads are so few in number in comparison with those supplied by the meshed network that they have been included in the meshed network.
- d) Charges for load group 4 (500 to 2499 kVA) and load group 5 (2500+ kVA) have been calculated on the basis that they are all HV metered installations; an additional charge will apply where Aurora owns the associated transformer and switchgear.
- e) Charges do not include energy losses on the distribution network. Energy retailers must purchase their share of system losses using the loss factors as published on Aurora's website [www.electricity.co.nz](http://www.electricity.co.nz).
- f) Charges exclude metering services involved with the provision of meters or meter reading. These services are provided by others.

### 4.2 Asset Valuation

Book values of the assets are allocated pro rata across asset groups based upon the ODV value.

### 4.3 Maintenance of Existing Assets

The maintenance programme is determined by; safety requirements, reliability objectives, and repairs to equipment following faults. The safety and reliability requirements set the planned programme for maintenance and are detailed in the Asset Management Plan.

The amounts budgeted for maintenance are detailed in the Asset Management Plan under the following categories:

- system control
- subtransmission lines and cables (33 kV)
- zone substations (33 kV to 11 kV and 6.6 kV transformation)
- HV lines and cables (11 kV and 6.6 kV)
- distribution substations (11/6.6 kV to 400 V transformation)
- LV lines and cables (400 V).

Use of the above assets by each load group determines the total cost to be recovered from each load group.

#### 4.4 Load Groups

The rationale for each load group is as follows;

- Load Group 0 - Unmetered connections less than 1 kVA with defined load pattern (subset of load group L1).
- Load Group 1 - Single phase 60 amp capacity connections or less that share LV asset costs.
- Load Group 2 - All remaining connections that share LV asset costs.
- Load Group 3 - Three phase connections that may share some LV asset costs.
- Load Group 3A - Three phase connections generally supplied direct from distribution transformer (subset of load group 3)
- Load Group 4 - Three phase connections supplied direct from distribution transformer - transformer may be owned by consumer and connections share general HV asset costs
- Load Group 5 - Three phase connections - generally HV consumers and have dedicated HV lines / cables to supply the connection

## 5 PRICING COMPONENTS

### 5.1 Distribution Cost-Recovery Components

#### 5.1.1 Standard Domestic Connections

A "Standard Domestic" connection is one where the connection capacity is either 15 kVA (single phase 60 amps) or 8 kVA (single phase 32 amps) and the electricity retailer advises Aurora that the electricity use is for domestic purposes. If there is a likelihood of injection of energy from the connection, then two-way import / export metering must be installed to remain on the Standard Domestic variable tariff.

Two components of line charges are used and the pricing details are outlined in Schedules 1 to 4 (A1, B1, C1, D1). The components are as follows:

##### 5.1.1.1 Fixed Component

The fixed component has been set at 10% of the total use-of-system charge for an 8,000 kWh per annum connection.

##### 5.1.1.2 Variable Components

The variable components are defined by the existing metering arrangements for each network area.

In the Dunedin area, most domestic connections have a single meter, which records general purpose and controlled water heating (16 hours service) consumption.

In the Central and Te Anau areas, most domestic connections have two meters – one to record general purpose consumption and one to record controlled water heating (16 hours service) consumption.

In both areas, the charges for controlled loads are discounted to reflect the lower contribution to peak loads by these loads.

#### 5.1.2 Other Connections (Non-Domestic Connections and Non-Standard Domestic Connections including street lighting)

Five components of line charges are used and the pricing details are outlined in Schedules 1 to 3 (A2, A3, B2, B3, C2, C3, D2, D3). The components are as follows:

##### 5.1.2.1 Fixed Charge

This charge recovers costs that are incurred on a connection basis.

##### 5.1.2.2 Assessed Capacity Charge

###### LV Metered Connections

This charge recovers costs associated with the distribution system local to each connection point, ie LV lines and cables, distribution substations, and HV lines and cables. The use of these assets is more directly related to the capacity of the individual connections.

The basis for the annual Assessed Capacity is the minimum fuse size, mains size or standard distribution transformer size required to supply the maximum anytime power demand. Normally this will be the minimum fuse size for capacity up to 276 kVA and installed distribution capacity for capacity greater than or equal to 300 kVA.

## HV Metered Connections

This charge recovers costs associated with the distribution system local to each connection point, ie HV lines and cables. The use of these assets is more directly related to the capacity of the individual connections.

The basis for the annual Assessed Capacity is the lesser of the installed distribution transformer capacity and minimum standard transformer capacity greater than 1.25 times the maximum anytime power demand (kVA). The factor of 1.25 is used so that the average ratio of maximum anytime power demand to Assessed Capacity for HV metered connections is the same as for LV metered connections in Load Groups 4 and 5. See also 4.1(d).

### 5.1.2.3 *kVA-km Charge*

For the L3, L3A, L4 and L5 load groups (assessed capacity 150 kVA or greater) the costs associated with HV lines and cables and subtransmission lines and cables are recovered by a kVA-km charge. The total kVA-km for each connection is the product of the connection capacity in kVA and the circuit distance from the distribution substation supplying the connection to the Aurora zone substation and then to the nearest Transpower supply point.

This charge recognises that additional investment in lines and cables is required to supply network connections that are a long way from Transpower supply points compared to those that are close to a Transpower supply point. At more remote locations, alternatives to electricity may be more appropriate and this component signals this fact.

### 5.1.2.4 *Congestion Period Demand Charge*

This charge recovers costs associated with zone substations and subtransmission lines and cables, which are sized for system peak loads.

The basis for the Congestion Period Demand (CPD kW) is the energy used at the installation when Aurora is managing demand. This energy usage will accumulate and at the end of the Congestion Period the accumulated energy is divided by the duration of the Congestion Period to obtain average power demand. If a consumer commences during the year a negotiated Congestion Period Demand will apply until a full winter is completed. The Congestion Period Demand for each installation is set at 1 October to the average of CPD kW (Previous Winter) and CPD kW (at 1 October previous year).

The Congestion Period is likely to occur on cold winter days, anytime between 7.30 am and 10.00 pm, and to last typically for two to three hours (but could last for up to ten hours on occasions) and is most likely to occur on approximately 20 to 50 days during the May to September period with most activity during June, July and August. The congestion will be signalled via ripple control whenever the Congestion Period applies. Consumers may use this to operate a warning device to directly control deferrable load or to start up a standby generator, whichever is the most convenient.

For connections where it is not presently economic to install Congestion Period Demand metering, then any charges that would normally be recovered via a Congestion Period Demand charge will be recovered via an Effective Congestion Period Demand charge based upon kWh consumption at the installation during Winter days (0700 hours - 2300 hours). This will be based upon the four month consumption during two two-monthly reading rounds or four one-monthly rounds. Energy consumed by defined night loads are discounted 100% and energy used by controlled loads are discounted 50% for their daytime energy. The effective Congestion Period Demand for each installation is set at 1 October to the average of CPD kW (Previous Winter) and CPD kW (at 1 October previous year). Thus a strong economic signal exists for consumers to accept controlled loads.

By signalling network congestion in this way, Aurora is able to defer the need for investment in more capacity, which is a very expensive alternative. Load is controlled only when the network loading is approaching the network's capacity. Consumers do not have to respond every time the signal is sent. Many will respond only when it suits, however the rewards for responding are substantial.

#### 5.1.2.5 *Equipment Charge*

This charge recovers costs associated with distribution substations for the load groups 500 to 2499 kVA and 2500+ kVA where the consumer has opted not to own their own transformers or switchgear.

## 5.2 **Transmission Cost-Recovery Components**

The following methodology is used as the basis for recovery of transmission charges. It best signals the transmission cost drivers that Transpower has reflected through its pricing structure. The same methodology is used to recover avoided Transpower Interconnection charges paid to TrustPower Ltd, Ravensdown Ltd and Pioneer Generation Ltd for the use of embedded generation at peak load times. Each component of transmission costs is allocated as follows:

### 5.2.1 **Connection Charges**

These charges have been allocated to load groups on the basis of 50% by each load group's share of anytime demand and 50% by each load group's share of winter day kWh. This improves the signalling of investment costs to those users who cause them.

### 5.2.2 **Interconnection Charges**

These charges have been allocated to each load group on the basis of the congestion period demand of each load group. The congestion period demand is the average demand of each load group whilst the load control service is being applied at the time of system load peaks. This is expected to apply for approximately 150 to 200 hours per year and mainly during the winter months of June, July and August.

### 5.2.3 **Standard Domestic Supply**

For Standard Domestic connections in load groups L1A (8 kVA) and L1 (15 kVA) the charges are recovered by a variable cents/kWh charge.

For other L1A (8 kVA) and other L1 (15 kVA) connections and the L2 (16-149 kVA) load group the connection charges are recovered by way of a charge per installed kVA capacity and the interconnection charge by way of a \$/kW using the previous year's winter day average demand.

For the L3 (150-249 kVA), L3A (250-499 kVA), L4 (500-2499 kVA) and L5 (2500+ kVA) load groups, the connection charges are recovered by way of a charge per installed kVA capacity and the interconnection charge by way of a charge per congestion period demand kW.

### 5.2.4 **Loss and Constraint Rental Rebates**

Loss and Constraint Rental Rebates are credits rebated by Transpower as a result of money received from the Clearing Manager for the Wholesale Electricity Market and are excluded from transmission charges. The rebates are allocated each month to Retailers on the basis of each retailers total transmission charges for the month in which the rebate applied. This credit is currently available in say mid-June for the month of April.

## **6 SEASONAL LOADS**

### **6.1 Background**

Aurora has a large number of seasonal loads connected to its network such as irrigation pumps, general pumps and fruit packing houses. Some connections, such as irrigation pumps, have been disconnected to avoid line charges over the winter period.

### **6.2 Line Pricing Recovery**

Aurora's use of system charges are based on recovery by equal monthly instalments of an annual charge, which is adjusted after each network congestion period to reflect prior-winter peak period usage. Deliberate disconnection for part of a year to avoid part year charges is unacceptable.

### **6.3 Policy**

For seasonal loads with capacity greater than 15kVA and advised to retailers, the following applies from 1 July 2006:

- 6.3.1 Any advice of a reconnection of a seasonal load that was disconnected within the previous 12 months will result in a Reconnection Charge equal to the monthly line charges not paid during the disconnected period, unless a written explanation satisfactory to Aurora is received.
- 6.3.2 Where disconnections occur for more than 12 months then Aurora reserves the right to remove assets dedicated to supply the de-energised ICPs and decommission the connection. Any request for subsequent reinstatement will be treated as if an application for a new connection was being made.
- 6.3.3 The Reconnection Charge will be invoiced to the retailer who requests the re-energisation and it is possible that the retailer will be back billed for up to 12 months of line charges. It is essential that new retailers accepting switches check whether the ICP has been de-energised on the Registry and if it is a seasonal load.

**SCHEDULE 1****AURORA CHARGES FROM 1 APRIL 2007*****SOUTH DUNEDIN AND HALFWAY BUSH GRID EXIT POINTS***

<b>A.1 - STANDARD DOMESTIC CONNECTIONS</b>		<b>Registry Code</b>	<b>Per Annum</b>	
			<b>Distribution</b>	<b>Transmission</b>
Fixed Annual Charge (15 kVA)		SHSD15	\$54.73	
Fixed Annual Charge (8 kVA) (note 6)		SHSD8	\$15.00	
<b>Uncontrolled Variable Charges</b>		<b>Tariff Code</b>	<b>(¢/kWh)</b>	
General Purpose	All day Summer	010S	4.87	0.75
General Purpose	All day Winter	010W	5.30	3.14
<b>Controlled Variable Charges</b>			<b>(¢/kWh)</b>	
General Purpose + 16 hour water heat	All day Summer	016S	2.73	1.08
General Purpose + 16 hour water heat	All day Winter	017W	4.02	1.70
Night + 3 hours	11 hour service	024	1.50	0.42
Night rate		028	0.68	0.00
Gen Purpose + 16 hour w/h - D/N	Summer Day	011S	4.74	0.90
Gen Purpose + 16 hour w/h - D/N	Winter Day	011W	5.04	3.66
Gen Purpose + 16 hour w/h - D/N	Summer Night	012S	0.68	0.00
Gen Purpose + 16 hour w/h - D/N	Winter Night	012W	0.68	0.00

<b>A.2 - STREET LIGHTING</b>		<b>Registry Code</b>	<b>Per Annum</b>	
			<b>Distribution</b>	<b>Transmission</b>
Fixed Annual Charge	0000201300DE692	SDNSTL	\$82,605	\$27,182
Fixed Annual Charge	0000203111DE930	HWBSTL	\$125,755	\$41,371

<b>A.3 - OTHER CONNECTIONS</b>				<b>Per Annum</b>			
	<b>Registry Code</b>	<b>Load Group</b>	<b>Capacity kVA</b>	<b>Fixed \$</b>	<b>Capacity \$/kVA</b>	<b>kVA-km \$/kVA-km</b>	<b>Congestion Period \$/kW</b>
Distribution	SH0	L0	0 - 1	\$103.60			
	SH0A	L0A (note 5)	0 - 2	\$215.07			
	SH1A	L1A (note 6)	0 - 8	\$10.08	\$10.96		\$87.91
	SH1	L1	0 - 15	\$10.08	\$9.47		\$87.91
	SH2	L2	16 - 149	\$17.33	\$17.92		\$66.55
	SH3	L3	150 - 249	\$388.00	\$23.75	\$0.25	\$53.83
	SH3A	L3A	250 - 499	\$388.00	\$21.97	\$0.25	\$53.83
	SH4	L4 (note 8)	500 - 2499	\$1,000.00	\$13.42	\$0.25	\$42.87
	SH5	L5 (note 8)	2500+	\$1,000.00	\$7.63	\$0.25	\$22.38
Transmission	SH0	L0	0 - 1	\$46.00			
	SH0A	L0A (note 5)	0 - 2	\$99.49			
	SH1A	L1A (note 6)	0 - 8		\$2.70		\$56.74
	SH1	L1	0 - 15		\$1.78		\$56.74
	SH2	L2	16 - 149		\$2.22		\$55.68
	SH3	L3	150 - 249		\$4.35		\$55.33
	SH3A	L3A	250 - 499		\$4.35		\$55.33
	SH4	L4	500 - 2499		\$4.35		\$55.33
	SH5	L5	2500+		\$4.35		\$55.33

Notes - Refer to Schedule 5

**SCHEDULE 2****AURORA CHARGES FROM 1 APRIL 2007*****CLYDE AND CROMWELL GRID EXIT POINTS***

<b>B.1 - STANDARD DOMESTIC CONNECTIONS</b>		<b>Registry Code</b>	<b>Per Annum</b>	
			<b>Distribution</b>	<b>Transmission</b>
Fixed Annual Charge (15 kVA)		CCSD15	\$54.73	
Fixed Annual Charge (8 kVA) (note 6)		CCSD8	\$15.00	
<b>Uncontrolled Variable Charges</b>		<b>Tariff Code</b>	<b>(¢/kWh)</b>	
General Purpose	All day Summer	101S	7.02	0.97
General Purpose	All day Winter	101W	9.26	2.69
<b>Controlled Variable Charges</b>			<b>(¢/kWh)</b>	
Peak Water Heating	20 hour service	109	5.25	1.35
Standard Water Heating	16 hour service	106	3.65	0.84
Night + 5 Hours	13 hour service	103	4.01	1.19
Night + 3 Hours	11 hour service	104	3.40	0.65
Night		108	3.24	0.00

<b>B.2 STREET LIGHTING</b>			<b>(¢/kWh)</b>	
Fixed Annual Charge per lamp		CCSTL	\$12.00	
Variable Charge		110	3.20	1.20

<b>B.3 - OTHER CONNECTIONS</b>				<b>Per Annum</b>			
	<b>Registry Code</b>	<b>Load Group</b>	<b>Capacity kVA</b>	<b>Fixed \$</b>	<b>Capacity \$/kVA</b>	<b>kVA-km \$/kVA-km</b>	<b>Congestion Period \$/kW</b>
Distribution	CC0	L0	0 - 1	\$134.58			
	CC0A	L0A (note 5)	0 - 2	\$255.80			
	CC1A	L1A (note 6)	0 - 8	\$11.98	\$21.38		\$122.93
	CC1	L1	0 - 15	\$11.98	\$19.61		\$122.93
	CC2	L2	16 - 149	\$19.99	\$26.98		\$92.28
	CC3	L3	150 - 249	\$477.00	\$32.13	\$0.24	\$88.11
	CC3A	L3A	250 - 499	\$477.00	\$29.62	\$0.24	\$88.11
	CC4	L4 (note 8)	500 - 2499	\$1260.00	\$24.50	\$0.24	\$88.11
	CC5	L5 (note 8)	2500+	\$1260.00	\$18.18	\$0.24	\$81.55
Transmission	CC0	L0	0 - 1	\$51.64			
	CC0A	L0A (note 5)	0 - 2	\$125.29			
	CC1A	L1A (note 6)	0 - 8		\$2.42		\$58.88
	CC1	L1	0 - 15		\$1.61		\$58.88
	CC2	L2	16 - 149		\$2.52		\$54.99
	CC3	L3	150 - 249		\$5.16		\$54.76
	CC3A	L3A	250 - 499		\$5.16		\$54.76
	CC4	L4	500 - 2499		\$5.16		\$54.76
	CC5	L5	2500+		\$5.16		\$54.76

Notes - Refer to Schedule 5



**SCHEDULE 3****AURORA CHARGES FROM 1 APRIL 2007*****FRANKTON GRID EXIT POINT- (excluding Frankton sub area)***

<b>C.1 - STANDARD DOMESTIC CONNECTIONS</b>		<b>Registry Code</b>	<b>Per Annum</b>	
			<b>Distribution</b>	<b>Transmission</b>
Fixed Annual Charge (15 kVA)		FRSD15	\$54.73	
Fixed Annual Charge (8 kVA) (note 6)		FRSD8	\$15.00	
<b>Uncontrolled Variable Charges</b>		<b>Tariff Code</b>	<b>(¢/kWh)</b>	
General Purpose	All day Summer	201S	5.15	1.22
	All day Winter	201W	6.15	3.39
<b>Controlled Variable Charges</b>			<b>(¢/kWh)</b>	
Peak Water Heating	20 hour service	209	3.30	1.37
Standard Water Heating	16 hour service	206	1.47	1.02
Night + 5 Hours	13 hour service	203	2.12	1.21
Night + 3 Hours	11 hour service	204	1.32	0.85
Night		208	1.18	0.00

<b>C.2 STREET LIGHTING</b>			<b>(¢/kWh)</b>	
Fixed Annual Charge per lamp		FRSTL	\$12.00	
Variable		210	2.53	1.33

<b>C.3 - OTHER CONNECTIONS</b>				<b>Per Annum</b>			
	<b>Registry Code</b>	<b>Load Group</b>	<b>Capacity kVA</b>	<b>Fixed \$</b>	<b>Capacity \$/kVA</b>	<b>kVA-km \$/kVA-km</b>	<b>Congestion Period \$/kW</b>
Distribution	FR0	L0	0 - 1	\$109.53			
	FR0A	L0A (note 5)	0 - 2	\$208.21			
	FR1A	L1A (note 6)	0 - 8	\$9.76	\$14.21		\$91.32
	FR1	L1	0 - 15	\$9.76	\$12.78		\$91.32
	FR2	L2	16 - 149	\$16.26	\$19.89		\$79.06
	FR3	L3	150 - 249	\$380.00	\$24.97	\$0.30	\$63.99
	FR3A	L3A	250 - 499	\$380.00	\$22.96	\$0.30	\$63.99
	FR4	L4 (note 8)	500 - 2499	\$1,004.00	\$16.81	\$0.30	\$63.99
	FR5	L5 (note 8)	2500+	\$1,004.00	\$8.37	\$0.30	\$47.98
Transmission	FR0	L0	0 - 1	\$49.90			
	FR0A	L0A (note 5)	0 - 2	\$105.07			
	FR1A	L1A (note 6)	0 - 8		\$6.72		\$54.60
	FR1	L1	0 - 15		\$5.91		\$54.60
	FR2	L2	16 - 149		\$5.98		\$53.85
	FR3	L3	150 - 249		\$10.92		\$53.68
	FR3A	L3A	250 - 499		\$10.92		\$53.68
	FR4	L4	500 - 2499		\$10.92		\$53.68
	FR5	L5	2500+		\$10.92		\$53.68

Notes - Refer to Schedule 5

**SCHEDULE 3A****AURORA CHARGES FROM 1 APRIL 2007*****FRANKTON GRID EXIT POINT – (Frankton sub area)***

A prudent discount policy applies in the Frankton sub area.

Pricing in the sub area is less than or equal to the standard Frankton GXP pricing. Lower distribution line charges within the sub area reflect lower costs to reticulate an area close to the Frankton GXP.

Frankton sub area is a defined area close to the FKN GXP. Affected ICPs are defined on the Registry by a pricing code of “FK” instead of the standard code of “FR”.

**SCHEDULE 4****AURORA CHARGES FROM 1 JUNE 2007*****HERITAGE ESTATE - TE ANAU AREA - NORTH MAKAREWA GRID EXIT POINT*****(Note11)**

<b>E.1 - STANDARD DOMESTIC CONNECTIONS</b>		<b>Registry Code</b>	<b>Per Annum</b>	
			<b>Distribution</b>	<b>Transmission</b>
Fixed Annual Charge (15 kVA)		HESD15	\$54.73	
Fixed Annual Charge (8 kVA) (note 6)		HESD8	\$15.00	
<b>Uncontrolled Variable Charges</b>		<b>Tariff Code</b>	<b>(¢/kWh)</b>	
General Purpose	All day Summer	401S	6.19	1.01
General Purpose	All day Winter	401W	7.82	2.97
<b>Controlled Variable Charges</b>			<b>(¢/kWh)</b>	
Standard Water Heating	16 hour service	406	2.65	0.87
Night + 3 Hours	11 hour service	404	2.36	0.72
Night		408	2.26	0.00

<b>E.2 STREET LIGHTING</b>			<b>(¢/kWh)</b>	
Fixed Annual Charge per lamp		HESTL	\$12.00	
Variable		410	2.83	1.16

<b>E.3 - OTHER CONNECTIONS</b>				<b>Per Annum</b>			
	<b>Registry Code</b>	<b>Load Group</b>	<b>Capacity kVA</b>	<b>Fixed \$</b>	<b>Capacity \$/kVA</b>	<b>kVA-km \$/kVA-km</b>	<b>Congestion Period \$/kW</b>
Distribution	HE0	L0	0 - 1	\$119.11			
	HE0A	L0A (note 5)	0 - 2	\$226.39			
	HE1A	L1A (note 6)	0 - 8	\$10.60	\$18.92		\$102.80
	HE1	L1	0 - 15	\$10.60	\$17.36		\$102.80
	HE2	L2	16 - 149	\$17.69	\$23.88		\$73.67
Transmission	HE0	L0	0 - 1	\$45.70			
	HE0A	L0A (note 5)	0 - 2	\$110.88			
	HE1A	L1A (note 6)	0 - 8		\$2.14		\$58.11
	HE1	L1	0 - 15		\$1.42		\$58.11
	HE2	L2	16 - 149		\$2.23		\$56.67

Notes - Refer to Schedule 5

## **SCHEDULE 5**

### **AURORA CHARGES FROM 1 APRIL 2007**

#### **NOTES**

- (1) All charges are exclusive of GST.
- (2) Variable charges apply to kWh as metered at each ICP. The hours of service for water heating loads are target minimum levels of service. In unusual network circumstances it may be necessary for the target level to be less.
- (3) Capacity provided is on the basis of the smaller of mains size, LV fuses or transformer capacity.
- (4) Load group L0 is for approved unmetered supplies only.
- (5) Load group L0A is for approved unmetered builders temporary supply with maximum capacity of 15 kVA and subject to special conditions.
- (6) 8 kVA connections require a sealed 32 Amp MCB installed on the meter board.
- (7) The Summer period is 1 October to 30 April and Winter is 1 May to 30 September.
- (8) For L4 and L5 load groups an additional \$5.20 per kVA of capacity applies if Aurora owns the distribution transformer.
- (9) An additional \$84.00 per kVAr per annum of equivalent corrective capacitance applies if the installation power factor is required to be improved to 0.95.
- (10) Loss & Constraint Rental Rebates are excluded from transmission charges and are credited separately.
- (11) Heritage Estate is a small 180 lot subdivision in the Te Anau area constructed in 2005.