Eastland Network Limited

Pricing Methodology Disclosure

Pursuant to:

Requirements 2.4 of the Electricity Information Disclosure Determination 2012

For Line Charges introduced on 01 April 2013

March 2013

Contents

INTRODUCTION

This document sets out Eastland Network Limited's (Eastland's) pricing methodology for the line charges in effect as at 1 April 2013.

Eastland's pricing methodology has been prepared to comply with Section 2.4 of the Electricity Information Disclosure Determination 2012 that requires ENL to annually discloses the following;

PRICING

- Description of the methodology used to calculate the prices payable or to be payable;
- Describe any changes in prices and target revenues from the previous year and explain reasons for the changes, and quantify the difference in respect of each of those changes;
- Explain the approach taken with respect to pricing in non-standard contracts and distributed generation;
- Explain whether the EDB has sought the views of consumers, including their expectations in terms of price and quality, and reflected those views in calculating the prices payable or to be payable. If the EDB has not sought the views of the consumers, the reasons for not doing so;
- Demonstrate the extent to which the pricing methodology is consistent with the pricing principles and explain the reasons for any inconsistency between the pricing methodology and the pricing principles;
- State the target revenue expected to be collected;
- Identify the key components of target revenue required to cover the costs and return on investment associated with the provision of electricity lines services;
- State the consumer groups for whom prices have been set, and describe-
    - The rationale for grouping consumers in this way;
    - the method and the criteria used to allocate consumers to each of the consumer groups;
- Describe the method used to allocate the target revenue among consumer groups, including the numerical values of the target revenue allocated to each consumer group, and the rationale for allocating it in this way;
- State the proportion of target revenue that is collected through each price component.

PRICING STRATEGY

- Explain the pricing strategy for the next five disclosure years, including the current disclosure year for which prices are set;
- Explain how and why prices for each consumer group are expected to change as a result of the pricing strategy;

If the pricing strategy has changed from the preceding disclosure year, identify the changes and explain the reasons for the changes.

NON-STANDARD CONTRACTS

Describe the approach to setting prices for non-standard contracts, including -

- the extent of non-standard contract use, including the number of ICPs represented by non-standard contracts and the value of the target revenue expected to be collected from consumers subject to non-standard contracts;
- how the EDB determines whether to use a non-standard contract, including any criteria used;
- any specific criteria or methodology used for determining prices for consumers subject to non-standard contracts and the extent to which these criteria or that methodology are consistent with the pricing principles;
- Describe the obligations and responsibilities (if any) to consumers subject to non-standard contracts in the event that the supply of electricity lines services to the consumer is interrupted. This description must explain –
- the extent of the differences in the relevant terms between standard contracts and non-standard contracts;
- any implications of this approach for determining prices for consumers subject to non-standard contracts.

DISTRIBUTED GENERATION

Describe the approach to developing prices for electricity distribution services provided to consumers that own distributed generation, including any payments made by ENL to the owner of any distributed generation, and including the

- prices
- value, structure and rationale for any payments to the owner of the distributed generation;

DERIVATION OF REVENUE REQUIREMENT

The first step in developing network prices is to determine network costs and the targeted revenue requirement with respect to the Price Path Threshold and the maximum permitted increases of prior year prices. The network cost structure for Eastland for the 2012/13 period is summarised in the following table and is comprised of two main components; distribution costs and transmission costs.

Eastland classes Electricity Commission levies, Commerce Act levies and local body rates as distribution costs and passes them through in full to consumers.

Distribution Costs	Distribution Revenue Requirement 2013/14
Network Operations and Maintenance	5,079,210
Indirect Costs	2,786,680
Pass Through Costs (Non-Transmission)	365,314
Network Depreciation	5,015,190
Taxation	1,633,933
Target Return on Investment	6,701,541
Total	**21,581,868**

Transmission Costs	Transmission Revenue Requirement 2013/14
Transpower	8,548,203
Avoided Transmission	2,527,590
Loss Rental Rebates	-55,000
Total	**11,020,793**

Table 1 – Revenue Requirement by component

DISTRIBUTION REVENUE REQUIREMENT

The distribution revenue requirement is made up of the following components:

- Network Operation and Maintenance Costs
- Indirect Costs
- Pass Through Costs (Non-Transmission)
- Network Deprecation
- Taxation
- Target Return on Investment.

NETWORK OPERATION AND MAINTENANCE COSTS, INDIRECT COSTS, PASS THROUGH COSTS (NON- TRANSMISSION), NETWORK DEPRECIATION AND TAXATION

The revenue requirement components including, network operation and maintenance, indirect, pass through (non transmission), network depreciation and taxation are based on budgeted costs for the 2013/14 period.

RETURN ON INVESTMENT

Return on investment revenue provides a return on investment to network owners and is determined as a product of asset value and the weighted average cost of capital. The target return on investment is determined using a weighted average cost of capital of 8.75%, however, the price path threshold creates a cap on this return and the actual return on investment may ultimately be less than this for the 2014 financial year.

TRANSMISSION REVENUE REQUIREMENT

Power supply on the East Coast is capacity constrained primarily by the Transpower owned connection assets i.e. the spur assets dedicated to the regions use. Traditional solutions to upgrading capacity and security standards do not represent the least cost solution. The cost of Transpower provided solutions have been determined via the New Investment Agreement Methodology that Transpower applies to such upgrades.

Eastland has determined that better load management, optimising the configuration of its sub-transmission system and the introduction of distributed generation present a lower risk and more economic solution. Consequently transmission recovery is intended to recognise the transmission benefit and avoidance of Transpower charges in order to fund these alternatives whether provided by Eastland or another party.

The transmission revenue requirement is made up of the following components:

- Transpower Charges
- Avoided Transmission Charges
- Loss Rental Rebates.

TRANSPOWER

Transpower charges are comprised of two charges, connection charges and interconnection charges. Connection charges are a fixed annual amount and interconnection charges are a fixed rate per unit of regional co-incident peak demand.

AVOIDED TRANSMISSION

Where an investor provides assets as an alternative to Transpower providing transmission services, such as distributed generation, the benefit of avoided transmission charges will be passed through to the investor on a deprival basis with value calculated per Transpower's transmission pricing methodology. The connection of generators to the Eastland network, and the charge/rebates applicable are subject to Eastland review on a case-by case basis.

Investment that increases capacity will be recognised via calculation of the connection charge, assuming Transpower upgrade. The benefit to consumers over the Transpower solution is that capacity can be delivered on a more capital-efficient basis. Investment that has the potential to reduce the regional co-incident peak demand at a GXP will be recognised via pass through of reductions in Tanspower's interconnection charge. Avoided transmission charges are based on the assessed impact of these alternatives will have on GXP load profiles both in terms of demand and kWhs.

The maximum potential for reduction in Transpower charges is dependent on operating assets in co-ordination with Eastland's load management and any other party's capability. The level of risk sharing between providers will be subject to contracted terms between parties.

It should be noted that the investor can equally be Eastland, any retailer, any generator or independent party. However, the capacity requirement is capped at the Eastland determined targets. Where there is a choice of alternative investments, preference will be given to the least cost solution to Eastland on offer at the time of commitment. As with Transpower new investment agreements, the commitment will be locked in for an agreed period and not subject to optimisation.

Based on the regulations set out in the Electricity Distribution Services Default Price-Quality Path Determination 2012, a distribution company can recover the costs of avoided transmission to its consumers and/or electricity retailers via line charges. The avoided cost of interconnection charge is calculated as the reduction in ENL's RCPD due to the contribution from DG in reducing the RCPD.

The avoided cost of connection charge is the total amount of connection charges that have been avoided due to the presence of DG on ENL's network. Connection charges may be avoided either by:

- Avoiding a new transmission connection asset; or
- Avoiding an existing transmission connection asset.

The amount of avoided connection charge is calculated based on the value of new transmission connection asset projects and/or existing transmission connection assets that have been avoided. The value of new transmission connection projects is converted to an avoided connection charge using Transpower's current pricing methodology for connection assets. The value of existing connection assets that are avoided is calculated based on the most recent connection charge (for the assets avoided) inflated to current costs.

LOSS RENTAL REBATES

Transpower loss rental rebates are excluded from the revenue requirement as these rebates are passed on transparently via a separate rebate mechanism, to Eastland's consumers and/or electricity retailers. A $55,000 administration fee is charged in relation to the determination of pass through amount payable to each retailer.

CONSUMER GROUPS

END-CONSUMER GROUPING

From 31 March 2010 Eastland changed consumer group classification from a high, medium, low density to a more simple high, low density classification. Consumers which previously belonged to the medium density classification have been migrated to either the high or low density groups dependent on their location on the Eastland network.

Areas of the network which exhibit high consumer density have been identified in Eastland's geographic information system (GIS) and the remainder of the network has been deemed low density. Separating the network and consumers into these new classifications allows Eastland to better examine the costs associated with supplying consumers in these two distinct areas and reflect the higher level of service offered to high density consumers. The high-low density segmentation exercise involved isolating areas of the network in Eastland's GIS and extracting the corresponding network asset and consumer usage data.

Consumers within each density classification are classed as either domestic or non-domestic consumers. Domestic consumers are grouped together because they share a similar network usage profile. Domestic consumer's peak usage occurs between the hours of 7:30am and 9:30am in the morning and 5:30pm and 9:00pm in the evening which corresponds with network peak demand. In contrast non-domestic consumers do not typically share a similar peak usage profile due to the diverse nature of their operations and as such are not able to be grouped in a similar manner. Eastland therefore groups non-domestic consumers based on their assessed capacity requirements using their installed fuse rating or transformer capacities where transformers are dedicated to supply of an individual consumer. This approach recognises that as consumer capacity requirement increase the value of assets employed to supply consumers' increases.

An installation only qualifies for domestic tariffs if it satisfies the following:

- It is the consumer's primary and permanent place of residence, i.e. excludes holiday homes, Shearers quarters, garages, pumps, trust owned properties etc.
- Only one installation control point (ICP) on a consumers account can be classed as domestic whether on Eastland Network Ltd or elsewhere.
- The installation is used as a residence and not for business purposes.
- Does not exceed the following current limits:

1 Phase	2 Phase	3 Phase
Up to 62 amps	Up 42 amps per phase	Up to 32 amps per phase

- All consumers wishing to change classification to the Domestic definition will be required to make a declaration, and supporting documentation such as appearing on the local electoral roll.

On 1 April 2010, Eastland introduced a new non-domestic Time of Use Tariff group. This tariff is available to non-domestic consumers who have an assessed demand of between 201kVA and 300kVA. This tariff was introduced following consumer requests and will give consumers, who are still relatively low energy consumers by non-domestic levels, the ability to manage their loads more effectively and take advantage of a time of use tariff. The feedback from retailers during consultation was positive with regards to introducing a new TOU tariff. The Eastland Cost of Supply model was also updated to reflect the introduction of this tariff.

Accordingly, Eastland employs the following consumer group classifications:

High Density
Domestic
Low Capacity (0 to 3kVA)
Demand (0 to 30kVA)
Demand (31 to 100kVA)
Demand (101 to 300kVA)
TOU - Demand (201-300kVA)
TOU - Demand (301-500kVA)
TOU - Demand (501-1000kVA)
TOU - Demand (1001-4500kVA)
TOU - Demand (4501-6500kVA)
Low Density
Domestic
Low Capacity (0 to 3kVA)
Demand (0 to 30kVA)
Demand (101 to 300kVA)
TOU - Demand (201-300kVA)
TOU - Demand (301-500kVA)
TOU - Demand (501-1000kVA)
TOU - Demand (1001-4500kVA)
TOU - Demand (4501-6500kVA)

Table 2 – Consumer Groups

COST ALLOCATION TO CONSUMER GROUPS

TRANSITION OF COST OF SUPPLY INTO CONSUMER GROUP TARIFFS

In developing the new high-low density classification Eastland completed a cost allocation exercise to determine the revenue requirement by consumer group that would be necessary to meet an efficient cost allocation. The cost allocation methodology set out in this document is based on that work and is included to demonstrate that Eastland have used this methodology to inform the price changes required and demonstrate that a sound methodology underpins Eastland's pricing decisions.

As Eastland are mindful of price shocks to consumers, the intention is to move prices towards those based on the revised cost allocation methodology over a period of 3-5 years. In doing so some load groups will face continual increases over this period while others will experience little or no change. It should be noted that future price movements may also be subject to changes in the regulations under which Eastland operates.

ALLOCATORS

Eastland's cost of supply model (COSM) contains the following input assumptions and statistics for the purpose of cost allocation. Allocators are split into two groups, those that are load independent, and those that are load dependent.

Load Independent

- Connections - ICPs

Load Dependent

- Demand - Anytime Maximum Demand
- Demand - Co-incident Peak Demand
- Consumption - kWh
- Asset Replacement Cost

Capacity and security upgrades result in reconfiguration of network feeders. These can result in changes to the criteria used to allocate asset value, load and ICPs. It has therefore been necessary to assume a static model of network configuration in order to create some stability in pricing.

ALLOCATION OF REVENUE REQUIREMENT AMONG CONSUMER GROUPS

Following the determination of the allocators, the revenue requirement, comprised of distribution and transmission requirements, is allocated between consumer groups.

ALLOCATION OF DISTRIBUTION REVENUE REQUIREMENT

The total revenue requirement (as depicted in table 1 section 3) has been allocated to consumer groups using the allocation methodology set out in the paragraphs which follow. A summary of the final allocation is shown in Appendix 1 and the statistics used are shown in Appendix 2.

General management, overheads and administration, depreciation on non-system fixed assets and non transmission pass through costs including Electricity Commission levies and Commerce Act levies have been allocated to consumer groups using each group's share of total connections. These costs do not vary with consumer asset usage and have been allocated on a fixed basis accordingly.

Target return on investment, deprecation, operations and maintenance, taxation and local body rates costs have been allocated to consumer groups based on each group's use of network assets measured in terms of asset value employed and split by demand share. For each density class Eastland has extracted network asset data from the GIS and the associated values of these assets from the asset register. Where assets are shared by high and low density consumers, consumer group demand has been used to apportion the asset values between the two density classes. Following the determination of the asset values for high and low density consumers the asset values are broken down further into the individual consumer groups using each group's share of total assessed demand for the corresponding density class.

Eastland have employed a network use cost allocation method for load dependent costs. This is consistent with the assumption that investment in network assets is driven by use. In general, peak demand drives the need for network augmentation and is created predominantly by domestic consumers. However in Eastland's case there has been little growth in peak demand so an equal split of peak (co-incident) and anytime maximum demand has been used in assessing consumer group demand. This also ensures that non-domestic consumers contribute to network costs as the majority of planned future investment relates to asset renewal and improved reliability, as opposed to network augmentation, through which all consumers benefit not just those consuming during peak periods.

ALLOCATION OF TRANSMISSION REVENUE REQUIREMENT

Eastland have allocated transmission costs to consumer groups using a close approximation to the methodology set out in Transpower's transmission pricing methodology. That is connection costs, where connection points are shared by more than one Transpower customer, are allocated based on each consumers share of anytime maximum demand at that connection point. In Eastland's case connection charges are allocated to consumer group's based on their share of total anytime maximum demand. Interconnection charges are allocated to consumers based on their share of total co-incident peak demand on Eastland's network.

Avoided transmission charges are allocated on the same basis as Transpower transmission charges.

PRICE STRUCTURE

Eastland uses ICP billing for charging end consumers. However Eastland does not charge all consumers their true cost of supply due to a number of factors including:

- Low user regulations which restrict the level of domestic fixed charges;
- The complexity, and potential arbitrary results in determining individual costs of supply;
- The desire to make the tariff schedule administratively simple;
- The desire to manage rate shock;
- There must be a smooth price transition between non-domestic consumer groups;
- Recognition of high levels of reliability in high density areas

The implication is that for some consumer groups the target return on investment component of the revenue requirement is not fully recovered.

DOMESTIC CHARGES

The low user fixed charge regulations cap fixed charges to domestic consumers at 15 cents+GST per day. Eastland have set domestic fixed charges at 15 cents+GST per day which is less than that determined by the cost allocation described earlier. As such the remainder of the fixed cost allocated to domestic consumers is recovered through variable charges.

All domestic consumers receive the benefit of the 15 cents+GST per day government policy intended to reward low consumption behaviour. As this is the only domestic fixed charge and is not optional, compliance with the 8,000 kWh per annum break-even requirement is automatic.

Three variable rates are offered to domestic consumers which reflect the metering options available on the Eastland network. These are uncontrolled, controlled and night rates and are priced at progressively lower rates to encourage consumption/the shift of consumption to periods outside of peak demand.

Electricity delivered to consumers via controlled metering allows Eastland to switch off load via ripple control to appliances connected to the controlled meter during periods of peak electricity demand. The price reduction is achieved through the reduction in peak period demand which drives transmission interconnection charges.

The Night Rate Tariff, which excludes street lighting, is a time controlled night rate which has been introduced to encourage the connection of larger more efficient fixed wire storage capacity appliances. This tariff is applicable for those devices only and to the time period, half hour ending, 23:30 to 07:00. This tariff has seen no real growth in terms of connections or consumption and therefore this tariff has been closed to all new connections and no existing connections will be permitted to connect to it. Eventually, this tariff will be phased out entirely.

Transmission costs which have been allocated to domestic consumers are recovered predominantly through variable charges with a small portion recovered through fixed daily charges. Transmission charges have been structured in the same manner as distribution charges.

NON-DOMESTIC CHARGES

In contrast to domestic charges there are no additional regulatory constraints that apply to the determination of non-domestic charges. It is however vital to set prices in such a manner that price stability and certainty is achieved. Non-domestic consumers have often made long term investment decisions based on cost inputs (including electricity) and this must be factored into price determination. Eastland are therefore limited in the rate shock that can be imposed on non-domestic consumers and as such are bound by legacy pricing in this regard. In order to move toward more cost reflective pricing a transition period as discussed in section 5.1 has been used. The cost of supply allocation previously examined has provided the direction in which non-domestic charges should move.

In addition, a smooth price transition between consumer groups as capacity requirements increase is required. This is to ensure that artificial incentives are not created for consumers to move from one capacity group to another to take advantage of lower prices available to consumer groups with different capacity requirements. This distorts a true cost of supply allocation but eliminates the price instability which flows from a cost of supply allocation where consumers move from one consumer group to another from year to year to exploit prices which relate to different capacity requirements.

Currently there is no location differential in the fixed charges to high and low density non-domestic consumers. However the cost allocation methodology used shows that the total value of assets used to supply low density consumers is significantly greater than that used to supply high density consumers. To reflect this finding an increase in the fixed charges to low density non-domestic consumers will be phased in over the transition period.

Variable charges to non-domestic consumers reflect the time of use pricing signals mentioned previously for domestic consumers. The process has been through a number of iterative cycles to smooth the transition from non time of use to time of use options.

As discussed above, a new Time of Use (TOU) tariff was introduced. To qualify for TOU charges consumers are required to have a capacity requirement greater than or equal to 200kVA and TOU metering. These connections tend to have high load factors and have less opportunity to vary load during production hours. As such TOU consumers prefer a higher level of fixed charging which consequently results in reduced peak demand signalling. This reduces the sensitivity of total charges to variation in consumption, which is predominantly outside of peak times, and reflects the decision to recover the majority of non-domestic costs through fixed charges. Some peak signalling is retained in the variable charges to encourage demand side management. It follows that, non-domestic consumer group variable prices decrease as the capacity of the consumer group increases.

DISTRIBUTED GENERATION

Distributed Generation pricing is determined in accordance with the Electricity Governance (Connection of Distributed Generation) Regulations 2007.

Distributed Generation capacity based connection tariffs are comprised of a Fixed Distribution charge only. A variable distribution component for energy flow from the generation installation through the distribution network is not charged. Similarly fixed and variable Transmission charges are not applied to Distributed Generation that do not export to the transmission grid. This pricing means that the Distributed Generator, (based on generation capacity) is charged only for the distribution assets employed to connect and distribute production.

In accordance with the regulations Eastland makes payments to distributed generators for Avoided Cost of Transmission. Annually these payments are based on the generators actual contribution to the reduction of transmission charges.

As set out in the Eastland Connection and Operation of Distributed Generation Policy Eastland will make payment to the Distributed Generator where they provide proven and long-term benefits to the distribution network, such as improvement of security of supply.

Payment for Reduction of Losses is not made, as the benefits are realized by the energy retailer and are passed on to end users. In addition, due to the varying load conditions typical in the distribution network, the assessment of the physical losses applicable to a single installation is typically complex, and as such Eastland does not financially recognize the reduction of losses.

Losses

The allocation of losses is not a contracted line function service and Eastland does not charge specific recoveries for losses.

However in the absence of agreed individual estimated loss calculations the following defaults can be applied to reconcile the difference between ICP and GXP meter readings. These are applicable to all time periods, at all GXPs and network locations.

Loss factors applicable to Eastland

- 400V connected supplies 1.0705
- 11kV connected supplies 1.0475

UNECONOMIC BYPASS

Eastland do not consider there is any risk of uneconomic by pass.

TRANSMISSION ASSETS

Eastland is currently engaged in a process to investigate the transfer of significant transmission assets from Transpower. Due to the early stage of the process pricing considerations regarding the potential transfer of any transmission assets has not been included in current pricing methodology.

PRICING PRINCIPLES

Information Disclosures require ENL to demonstrate consistency with the pricing principles published by the Electricity Commission in March 2010 and adopted and amended by the Electricity Authority from time to time.

(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.*

(ii) *Having regard, to the extent practicable, to the level of available service capacity.*

(iii) *Signalling, to the extent practicable, the impact of additional usage on future investment costs.*

Being a largely fixed cost business, ENL's prices should also be largely fixed, however, due to the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004, ENL is required to limit it's fixed cost charges for domestic homes to 15c per day. Until this rule is relaxed there will continue to be subsidised electricity distribution charges of domestic homes in the Eastland region.

ENL's tariff structure divides customers according to capacity thereby signalling the economic cost of service provision based on capacity.

ENL utilises a variable pricing structure to signal the impact of usage during peak times. This is particularly so with the Time of Use (TOU) and controlled load tariffs which allow the customer or the network to reduce load during peak periods.

(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.

The structure of ENL pricing is to reward customers that have controllable load with lower prices. Further, industrial and commercial users have the option of selecting TOU pricing plans which encourage demand during non-peak periods.

(C) PROVIDED THAT PRICES SATISFY (A) ABOVE, PRICES SHOULD BE RESPONSIVE TO THE REQUIREMENTS AND CIRCUMSTANCES OF STAKEHOLDERS IN ORDER TO:

I. DISCOURAGE UNECONOMIC BYPASS;

II. ALLOW FOR NEGOTIATION TO BETTER REFLECT THE ECONOMIC VALUE OF SERVICES AND ENABLE STAKEHOLDERS TO MAKE PRICE/QUALITY TRADE-OFFS OR NON-STANDARD ARRANGEMENTS FOR SERVICES; AND

III. WHERE NETWORK ECONOMICS WARRANT, AND TO THE EXTENT PRACTICABLE, ENCOURAGE INVESTMENT IN TRANSMISSION AND DISTRIBUTION ALTERNATIVES (E.G. DISTRIBUTED GENERATION OR DEMAND RESPONSE) AND TECHNOLOGY INNOVATION

Discouragement of uneconomic bypass via distribution line pricing is limited as Eastland see no real risk of bypass in this region. There is some flexibility with regard to capital contributions for new connections at which point customers are able to make price quality trade-offs. For further information please refer to the Capital Contributions Policy.

ENL does not charge consumers with small scale distribution who re-inject back into the network, therefore ENL does not discourage small scale distributed generation connected to the network.

(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.

Development of prices is disclosed in this document which is publically available. Tariff categories have remained unchanged for a number of years with relatively small increases year on year. Eastland is very cognizant of the consumer base in the region and conscious of the impact any changes will have to this community.

Appendix 1 – Consumer Group Cost Allocation

Tariff Group		Network Operations and Maintenance	Indirect Costs	Pass Through Costs (Non-Transmission)	Network Depreciation	Taxation	Transpower	Avoided Transmission	Loss Rental Rebates	**Direct Cost Recovery**	**Effective Return on Investment**	*Rounding Adjustment*	**Total Revenue**
High Density	Domestic	974,192	1,498,262	115,426	961,913	313,388	3,290,972	1,096,885	-16,771	8,234,266	1,286,722		9,520,988
	Low Capacity (0 to 3kVA)	5,029	14,077	894	4,966	1,618	16,015	4,475	-112	46,963	17,644		64,607
	Demand (0 to 30kVA)	206,295	177,762	17,877	203,695	66,363	634,550	156,334	-4,467	1,458,409	979,854		2,438,263
	Demand (31 to 100kVA)	178,546	29,245	9,608	176,296	57,437	568,548	158,877	-4,140	1,174,417	225,863		1,400,280
	Demand (101 to 300kVA)	69,489	6,438	3,507	68,613	22,354	369,292	103,197	-2,468	640,422	10,602		651,024
	TOU - Demand (201-300kVA)	5,889	546	297	5,815	1,894	31,296	8,745	-60	54,422	-22,296		32,126
	TOU - Demand (301-500kVA)	25,788	1,746	1,271	25,463	8,296	137,047	38,297	-1,591	236,315	55,143		291,458
	TOU - Demand (501-1000kVA)	89,843	2,292	4,250	88,711	28,902	477,463	133,424	-4,972	819,913	-26,446		793,467
	TOU - Demand (1001-4500kVA)	41,926	109	1,938	41,397	13,487	177,258	6,777	-916	281,976	-152,751		129,225
	TOU - Demand (4501-6500kVA)	82,274	109	3,798	81,237	26,467	430,122	113,516	-4,593	732,930	-155,536		577,394
	Total High Density	**1,679,271**	**1,730,585**	**158,865**	**1,658,105**	**540,205**	**6,132,564**	**1,820,528**	**-40,090**	**13,680,033**	**2,218,799**	**0**	**15,898,832**
Low Density	Domestic	1,970,463	673,399	122,535	1,945,627	633,879	1,417,802	472,555	-7,764	7,228,496	2,601,898		9,830,393
	Low Capacity (0 to 3kVA)	9,882	11,785	1,010	9,758	3,179	6,400	1,504	-52	43,466	18,591		62,057
	Demand (0 to 30kVA)	644,603	359,998	46,660	636,478	207,362	417,437	98,104	-3,445	2,407,197	2,993,017		5,400,214
	Demand (31 to 100kVA)	191,299	9,166	9,251	188,888	61,539	123,883	29,115	-853	612,288	-6,500		605,789
	Demand (101 to 300kVA)	53,067	1,200	2,503	52,399	17,071	40,923	9,618	-216	176,565	-39,710		136,855
	TOU - Demand (201-300kVA)	0	0	0	0	0	0	0	0	0	0		0
	TOU - Demand (301-500kVA)	61,755	327	2,862	60,976	19,866	47,622	11,192	-268	204,333	-110,283		94,050
	TOU - Demand (501-1000kVA)	48,526	109	2,242	47,915	15,610	37,421	8,795	-136	160,482	-111,434		49,048
	TOU - Demand (1001-4500kVA)	420,344	109	19,384	415,046	135,221	324,150	76,180	-2,175	1,388,260	-857,384		530,876
	TOU - Demand (4501-6500kVA)	0	0	0	0	0	0	0	0	0	0		0
	Total Low Density	**3,399,939**	**1,056,095**	**206,449**	**3,357,086**	**1,093,728**	**2,415,639**	**707,062**	**-14,910**	**12,221,087**	**4,488,195**	**0**	**16,709,282**
	Rounding Adjustment												-5,453
	Total Network	**5,079,210**	**2,786,680**	**365,314**	**5,015,190**	**1,633,933**	**8,548,203**	**2,527,590**	**-55,000**	**25,901,120**	**6,706,994**	**-5,453**	**32,602,661**

Appendix 2 - Consumer Group Statistics

Consumer Group	Number of ICPs		
	High Density	Low Density	Total
Domestic	13,730	6,171	19,901
Low Capacity (0 to 3kVA)	129	108	237
Demand (0 to 30kVA)	1,629	3,299	4,928
Demand (31 to 100kVA)	268	84	352
Demand (101 to 300kVA)	59	11	70
TOU - Demand (201-300kVA)	5	-	5
TOU - Demand (301-500kVA)	16	3	19
TOU - Demand (501-1000kVA)	21	1	22
TOU - Demand (1001-4500kVA)	1	1	2
TOU - Demand (4501-6500kVA)	1	-	1
Total	15,859	9,678	25,537

Consumer Group	Consumption (kWh) for each Consumer Group		
	High Density	Low Density	Total
Domestic	86,599,596	40,090,757	126,690,353
Low Capacity (0 to 3kVA)	577,333	268,567	845,900
Demand (0 to 30kVA)	23,067,819	17,787,672	40,855,491
Demand (31 to 100kVA)	21,379,579	4,404,948	25,784,526
Demand (101 to 300kVA)	12,742,258	1,117,799	13,860,056
TOU - Demand (201-300kVA)	311,393	-	311,393
TOU - Demand (301-500kVA)	8,216,765	1,385,695	9,602,460
TOU - Demand (501-1000kVA)	25,671,757	704,078	26,375,835
TOU - Demand (1001-4500kVA)	4,730,424	11,228,937	15,959,361
TOU - Demand (4501-6500kVA)	23,714,624	-	23,714,624
Total	207,011,548	76,988,452	284,000,000

Consumer Group	AMD (kW) for each Consumer Group		
	High Density	Low Density	Total
Domestic	25,937	11,174	37,111
Low Capacity (0 to 3kVA)	162	77	239
Demand (0 to 30kVA)	7,288	4,991	12,279
Demand (31 to 100kVA)	5,750	1,481	7,232
Demand (101 to 300kVA)	3,735	489	4,224
TOU - Demand (201-300kVA)	317	-	317
TOU - Demand (301-500kVA)	1,386	569	1,956
TOU - Demand (501-1000kVA)	4,829	447	5,277
TOU - Demand (1001-4500kVA)	3,566	3,876	7,441
TOU - Demand (4501-6500kVA)	4,627	-	4,627
Total	57,598	23,105	80,703

Consumer Group	CPD (kW) for each Consumer Group		
	High Density	Low Density	Total
Domestic	25,937	11,174	37,111
Low Capacity (0 to 3kVA)	106	36	141
Demand (0 to 30kVA)	3,697	2,320	6,016
Demand (31 to 100kVA)	3,757	688	4,445
Demand (101 to 300kVA)	2,440	227	2,668
TOU - Demand (201-300kVA)	207	-	207
TOU - Demand (301-500kVA)	906	265	1,170
TOU - Demand (501-1000kVA)	3,155	208	3,363
TOU - Demand (1001-4500kVA)	160	1,801	1,962
TOU - Demand (4501-6500kVA)	2,684	-	2,684
Total	43,049	16,719	59,768

CERTIFICATE FOR YEAR-BEGINNING DISCLOSURES

Pricing Methodology

Clause 2.9.1 of Section 2.9

We, Roger Neil Taylor and Michael John Glover, being directors of Eastland Network Limited certify that, having made all reasonable enquiry, to the best of our knowledge-

a) the following attached information of Eastland Network Limited prepared for the purposes of clause 2.4.1 of the Electricity Distribution Information Determination 2012 in all material respects complies with that determination.

b) The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

Dated this 20th day of March 2013.

Roger Neil Taylor

Michael John Glover